STATE OF MICHIGAN

MICHIGAN ADMINISTRATIVE HEARING SYSTEM

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the Commissions own motion establishing the method and avoided cost calculation for DTE ELECTRIC COMPANY to fully comply with the Public Utilities Regulatory Policy Act of 1978, 16 USC 2001 et seq.	)	Case No. U-18091

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on March 31, 2017.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before April 21, 2017, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before May 5, 2017. **The Commission has selected this case for participation in its Paperless Electronic Filings Program. No paper documents will be required to be filed in this case.**

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Martin D. Snider Martin D. Snider
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Martin D. Snider
Administrative Law Judge

March 31, 2017
Lansing, Michigan

S T A T E O F M I C H I G A N

MICHIGAN ADMINISTRATIVE HEARING SYSTEM

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the Commissions own	)	
motion establishing the method and	)	
avoided cost calculation for DTE	)	Case No. U-18091
ELECTRIC COMPANY to fully comply	)	
with the Public Utilities Regulatory	)	
Policy Act of 1978, 16 USC 2001 et seq.	)	

<u>PROPOSAL FOR DECISION</u>

Issued and Served: March 31, 2017

TABLE OF CONTENTS

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the Commissions own motion establishing the method and avoided cost calculation for DTE ELECTRIC COMPANY to fully comply with the Public Utilities Regulatory Policy Act of 1978, 16 USC 2001 et seq.	))))))	Case No. U-18091

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On October 27, 2015 in U-17973, the Michigan Public Service Commission (Commission) opened an investigation into the related subjects of the Public Utility Regulatory Policies Act of 1978, 16 USC 2601 et seq (PURPA), and the avoided cost amounts that a public utility is required to pay to certain PURPA defined Qualifying Facilities (QFs) In its order the Commission noted that the Commission's two decades old avoided cost calculation methodology did not take in account significant changes in contemporary energy related issues and no longer was an appropriate method for the calculation of avoided costs of soon to expire PURPA QF contracts.

To facilitate the development of an updated PURPA QF avoided cost methodology the Commission's order directed the Commission's Electric Reliability Division staff (Staff) to form a Technical Advisory Committee (TAC) to engage representatives from electric utilities, electric cooperatives, QFs, small power producers and distributed generation advocates to develop avoided cost recommendations to the Commission. Subsequently the TAC met on numerous occasions, developed its avoided cost recommendations and prepared a final TAC report for the Commission's review and consideration. On April 8, 2016, in U-17973, Staff filed the Final TAC report with the Commission.

On July 3, 2016, the Commission issued an Order in the present matter directing DTE Electric Company (DTE) and other regulated utilities to file proposed avoided cost methodologies and costs by June 17, 2016. Specifically the Commission directed DTE to provide avoided cost valuations using (1) the hybrid proxy plant method proposed in the TAC's PURPA report; (2) the transfer price method developed under 2008 PA 295; (3) another method, if any, DTE wished to propose; and (4) DTE's proposed standard tariffs, including applicable design capacity. On June 17, 2016 DTE filed its avoided cost calculation using Staff's TAC hybrid proxy method, and DTE's proposed method. DTE also filed a proposed standard tariff.

On July 5, 2016 Landfill Energy Systems filed a Petition for Intervention. On July 13, 2016 the Michigan Environmental Council (MEC) filed a Petition for Intervention. On July 14, 2016 the City of Ann Arbor, Environmental Law and Policy Center (ELPC), Great Lakes Renewable Energy Association (Great Lakes), filed Petitions to Intervene.

On July 20, 2016, DTE filed an Objection to the invention of Environmental Law and Policy Center the Ecology Center the Solar Energy Industries Association and Vote Solar.

On July 21, 2016, Administrative Law Judge Mark Cummins convened a prehearing on this matter. During the prehearing the parties mutually agreed upon a schedule which included, among other things, a January 12, 2017 date for cross examination. ALJ Cummins also granted the City of Ann Arbor, MEC, Great Lakes, and the ELPC petitions to intervene.

On December 19, 2016, Andre Friedlis Administrative Law Manager, Michigan Administrative Hearing System, issued an Order of Reassignment which assigned this matter to ALJ Martin D. Snider.

On December 1, 2016: the City of Ann Arbor filed the Direct Testimonies and Exhibits of Peter Richardson and Brian Steglitz; the MPSC Staff (Staff) filed the Direct Testimony & Exhibits of Julie K. Baldwin, Jesse J. Harlow & Kevin S. Krause; ELPC filed Direct Testimony and Exhibits of Karl Rabago, Douglas Jester, Rand Dueweke, and Adam Schumaker; and Great Lakes filed Direct Testimony and Exhibit of Geoffrey C. Crandall.

On December 22, 2016, DTE filed Rebuttal Testimony and Exhibits of T. A. Bloch and Rebuttal Testimony of L. K. Mikulan and J. R. Padgett; the City of Ann Arbor filed Rebuttal Testimony & Exhibit of Brian Steglitz; ELPC filed Rebuttal Testimony of Douglas Jester on behalf of the ELPC, the Ecology Center, the Solar Energy Industries Association, and Vote Solar.

On January 12, 2017 a hearing on the matter was convened during which DTE's witnesses were cross examined and the following evidence was admitted and bound into the record:

For DTE: Direct, Revised Direct, and Rebuttal Testimony of Laura Mikulan and Exhibits A- 1, A-2, A-3, A-4 and A-5.

Direct and Rebuttal Testimony of James R. Padgett

Direct and Rebuttal Testimony of Timothy A. Bloch and Exhibits A-6, A-7, A-8 and A-9.

For MPSC Staff: Direct Testimony of Julie K. Baldwin, Jesse J. Harlow and Kevin S. Krause and Exhibits S-1, S-2, S-3, S-4 and S-5.

For the City of Ann Arbor: Direct Testimony of Peter Richardson, and Brian Steglitz and Rebuttal Testimony of Brian Steglitz and Exhibits CA-1 through CA-23.

For Great Lakes: Direct Testimony of Geoffrey C. Crandall and Exhibit GCC-1

For ELPC: Direct Testimony of Karl Rabago, Douglas Jester, Rand Dueweke and Adam Schumaker, Rebuttal Testimony of Douglas Jester and Exhibits ELP-1, ELP-2, ELP-3, ELP-4, ELP-5, ELP-6, ELP-7 and ELP-8.

On February 2, 2017, DTE, and Staff filed Initial Briefs. On March 2, 2017, DTE, and Staff filed Reply Briefs. The record consists of 364 transcript pages and 47 exhibits.

II.

BACKGROUND

On October 27, 2015, the Commission, in U-17973, commenced an investigation into the continuing appropriateness of the Commission's current regulatory implementation of the Public Utility Regulatory Policies Act of 22 1978. (PURPA). The Commission noted in its order that the Commission's two decades old avoided cost calculation methodology does not take in account significant changes in contemporary energy related issues and no longer was an appropriate method for the calculation of avoided costs for soon to expire PURPA QF contracts. The Commission also noted that, due to the imminent expiration of certain PURPA contracts (See Exhibit S-3 Appendix B), it would be prudent for the Commission to complete a review of the Commission's current approved methods for establishing PURPA QF avoided costs.

According to the Commission's order in U-17973 Commission staff (Director of the MPSC Staff's Electric Reliability Division) formed a Technical Advisory Committee (TAC). This committee was comprised of representatives of PURPA interests including, but not limited to, DTE and MPSC Staff. Subsequently the TAC met five times between December 2015 and March 2016. During these meetings participants discussed issues related to the Commission's current and future PURPA implementation with a specific focus on PURPA avoided costs methodologies. On April 8, 2016 the TAC issued a Final Report (TAC Report). See Exhibit S-3.

On May 3, 2016 in U-18091, the Commission directed DTE to file proposed avoided cost methodologies and costs in this docket by June 17, 2016. The Commission specifically directed DTE to provide separate avoided cost calculations using the following methods and to provide a recommended standard offer tariff:

(1) Hybrid proxy plant method developed by Staff in their April 8, 2016 Final TAC report (in U-17973);

(2) Transfer Price method developed under 2008 PA 295;

(3) Another method, if any, that DTE wished to propose; and

(4) Proposed standard offer tariff including applicable design capacity.

On June17, 2016 DTE complied with the order by filing a report containing the requested PURPA Avoided Cost Methodologies along with a Standard Offer Tariff.

DTE currently has several active PURPA contracts, the first of which expires in 2023. Only four DTE's PURPA contracts will expire before 2030. See Exhibit S-3 Appendix B TAC Final Report.

A. PURPA "Qualifying Facilities"

PURPA "Qualifying Facilities" (QFs), are defined as qualifying cogeneration facilities or qualifying small power production facilities that have a right to be served by, and sell to, the electric utility of their choosing at a cost that does not exceed "the incremental cost to the electric utility of alternative electric energy." PURPA § 210(b); 16 USC § 824a-3(b).

This PURPA "must purchase" obligation applies to all energy and capacity made available for sale from a QF and applies to all electric utilities, unless FERC grants a waiver. 18 CFR § 292.303(a); 18 CFR § 292.309.

B. Avoided Costs

FERC regulations require a utility to purchase electricity from QF's at rates equal to the utility's full avoided cost. 18 CFR § 292.304. PURPA defines the "incremental cost of alternative electric energy" as:

> "[t]he cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." PURPA § 210(d); 16 USC § 824a-3(d).

FERC regulations define "avoided costs" as the:

> "Incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 CFR § 292.101(b) (6).

Avoided costs are commonly determined by the following FERC-accepted methods.

- Proxy Unit Method
- Peaker Unit Method
- Differential Revenue Requirement
- IRP Based Avoided Cost Method
- Market Based Pricing
- Competitive Bidding

All these methods have been determined by FERC as reasonable methods for determining the avoided cost, and therefore are consistent with the PURPA's incremental cost definition.

Each avoided cost method include certain problems or concerns. For example, the conversion of fixed and variable costs to accurate capacity and energy costs. Sources of generation such as nuclear and hydro have high fixed and low variable costs while single cycle natural gas have low fixed and high variable costs. 2 TR 87.

Depreciation rates also vary making establishment of appropriate depreciation rates problematic. Because generation technologies components are different it is difficult to set the correct depreciation rate. The actual depreciation rate depends, and varies, according to the forecasted life of the facility, interim capital additions and retirement's projections, and end-of-life salvage value. *Id.*

A review of the various PURPA avoided costs methods may be found in a report prepared by Carolyn Elefant, titled "Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and A Path for Reform," . See Exhibit S- 3 TAC report reference materials.

C. Avoided Cost Methodologies

1. Proxy Unit Method

The proxy unit method involves the selection a proxy plant and then using the costs of that unit to determine avoided costs for capacity and energy. Michigan's initial PURPA cases used this method with a proxy coal plant. The proxy plant selected as the hypothetical generating unit, includes all future build uncertainties. 2 TR 87.

2. Peaker Unit Method

The Peaker unit method uses a peaker plant instead of a proxy plant and is designed to approximate the marginal cost of electricity, which is higher than the average cost of electricity. The use of the marginal cost of electricity may be reasonable because it's compatible with the definition of incremental cost of electricity and because FERC has accepted this method. More than likely, a current peaker unit would be a single cycle natural gas unit. Because a peaking unit is intended to have high on peak availability, while an intermittent resource (a QF) may not, the use of the peaking method may be problematic. 2 TR 88.

3. IRP Based Avoided Cost Method

This method uses an integrated resource plan (IRP) to produce values for energy and capacity. IRPs often require the use of complex software to:

- Run simulations of the current electricity system;
- Create forecasts for demand growth and generation retirements;
- Determine when capacity will be needed (based on supply and demand) and;

- Determine what type of generation is most likely to be beneficial to the system.

IRPs forecasts can identify the market prices and energy and capacity which could be used to determine avoided cost. Some utilities have the necessary IRP forecast software, and QFs and state commissions may not. Therefore they may have to rely on a third parties for an IRP analysis. *Id.*

4. <u>Market Based Pricing</u>

Developments in markets for energy and capacity has increased the interest in market based avoided cost methodologies, particularly in fully deregulated environments where all generation is dependent on the market for cost recovery. In MISO, all generation participates in the energy market to determine economic dispatch, but actual costs for a majority of the market, are recovered from customers through traditional utility ratemaking. MISO generation does not participate in the current capacity market. Because entities like MISO design the market structure and rules, market based pricing methodologies often result in the transfer some control from state commissions to ISOs/RTOs. *Id.*

5. <u>Competitive Bidding</u>

This method relies upon a utility issuing requests for proposal (RFP) and then using the results to determine a competitive price for energy and capacity. This process often involves expectations regarding bidder qualifications, access to capital, previous experience, employee safety, etc. The bidding process requires a sufficient number of qualified bidders. QFs may participate in the RFP process, or may wait to see if the rates resulting from the process are acceptable. The RFP process can be time consuming, challenging to set up due to a variety of opinions regarding appropriate RFP ground rules. *Id.*

D. PURPA

PURPA was enacted in 1978 to further U.S. energy independence and to address a nationwide energy crisis. As provided in the Act:

> "The purposes of this title are to encourage—
>
> (1) Conservation of energy supplied by electric utilities;
>
> (2) The optimization of the efficiency of use of facilities and Resources by electric utilities; and
>
> (3) Equitable rates to electric consumers."

The purpose of PURPA, with regard to renewables, was to provide reasonable access to the grid. PURPA's "full avoided cost" standard is not designed to produce direct savings to a utility's ratepayers, but was designed to decrease U.S. reliance on fossil fuels and to promote energy efficiency. PURPA was not designed, nor intended, to provide energy and capacity to an electric utility's ratepayers at a discount nor savings from the rates the utility would otherwise charge.

PURPA prohibits utilities from: (1) refusing to interconnect with QFs, (2) refusing to sell power to QFs at non-discriminatory rates, and (3) not fairly compensating QFs for power sold back to the utility. 2 TR 138. PURPA Section 210(b) requires an "electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility" at rates that are:

> "[j]ust and reasonable to the electric consumers of the electric utility and in the public interest," and does "not discriminate against qualifying cogenerators or qualifying small power producers."
>
> 16 USC § 824a-3(b).

E. FERC Waiver of PURPA Must Purchase Obligation

In 2005 Congress passed The Energy Policy Act of 2005 which added a new PURPA section (210(m)). If a QF has access to a sufficiently competitive market to sell its power, PURPA section 210(m) allows FERC to exempt utilities from entering into new purchase or contract obligations. Specifically, FERC may exempt a utility from its must-purchase obligation if FERC finds that the QF has nondiscriminatory access to:

(1) Independently administered, auction-based day-ahead and real-time wholesale markets and wholesale markets for long-term sales of capacity and energy (e.g., MISO, PJM, ISONE, NYISO),

(2) A regional transmission organization ("RTO") with competitive wholesale markets, or

(3) Wholesale markets that are comparable to (1) or (2).

Electric utilities may file an application with FERC to obtain a Section 21 exemption from PURPA's must-purchase provisions. During FERC's application review QFs may, under FERC rules, rebut the presumption of access because of operational characteristics or transmission constraints.

FERC regulations create a rebuttable presumption that QFs larger than 20 MW have non-discriminatory access to at least one of these competitive markets. FERC regulations also create a rebuttable presumption that a QF with a capacity at or below 20 MW does not have nondiscriminatory access to these markets. 18 CFR § 292.309(d) (1). On October 26, 2009 DTE received a FERC "must- purchase" waiver for QFs greater than 20 MW (FERC Docket Nos. QM10-2-20 000, QM10-2-001, QM10-2-002). DTE has not obtained a FERC waiver which relieves DTE from its PURPA mandatory purchase obligation from QFs 20 MW and lower.

F. <u>Must Purchase Obligation</u>

An electric utility must purchase energy and capacity made available from a QF at that utility's avoided costs. An electric utility, to which a QF can deliver power, must purchase a QF’s power at the electric utility’s avoided cost. FERC divides avoided costs into its two components: energy or capacity. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). Energy costs represent the cost of fuel and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy. Capacity costs are primarily the capital costs of a utilities facilities.

In FERC Order 69 FERC indicated that if a QF:

> "[o]ffers energy or sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rate for such a purchase will be based on the avoided capacity and energy costs."

FERC Order 69, 45 Fed. Reg. 12214, 12226, February 25, 1980.

FERC regulations outline “factors affecting rates for purchase” that should be considered in combination with energy and capacity considerations, when determining a utility’s avoided cost. FERC regulations provide that the following factors “shall, to the extent practicable, be taken into account.” 18 CFR § 292.304(e).

(1) Data regarding the utility’s cost structure and plans to add capacity;

(2) The availability of capacity or energy from a qualifying facility during daily and seasonal peak periods, including:
- (i) The ability of the utility to dispatch the qualifying facility;
- (ii) The reliability of the QF;
- (iii) Contract terms;

(iv) The extent to which scheduled outages of the qualifying facility can be coordinated with scheduled outages of the utility's facilities;
(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies;
(vi) The individual and aggregate value of energy and capacity from QFs on the electric utility's system;
(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from QFs.

(3) The relationship of the availability of energy or capacity from the QF to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

18 CFR 292.304(e)

FERC regulations also identify two other considerations:

- The ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

- The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a QF.

18 CFR § 292.304(e) (3) & (4)

PURPA Sections 201 and 210 promote development of small power renewable production and cogeneration facilities. QFs may generate power from renewable sources, or may utilize combined heat and power generation. Despite these PURPA provisions a utilities must-purchase obligation does not depend on the renewable nature of a particular QF. However, PURPA does take into account any value that is added by a QF using a renewable resource. FERC has recognized that power produced from renewable resources may contribute to the "reduction of fossil fuel use", may add value to the utility and its customers, and any additional value should be reflected in the avoided cost set for that facility. See 18 CFR § 304(e) (3). The “additional value” relates to measurable avoided costs and not extrinsic environmental adders.

Renewable Energy Credits (RECs) may be part of the value provided, when the environmental values are reflected in the avoided cost calculation. Environmental values, or RECs, may not necessarily be reflected in or captured by standard avoided cost calculations under PURPA.

G. DTEs Standard Offer Tariff

The Commission’s Order instructed DTE to provide “proposed standard rate tariffs, including applicable design capacity.” In response to the Commission’s order DTE filed a single tariff option. The TAC report includes Staff’s recommendation regarding the standard officer tariff QF capacity cap.

> “Staff supports a standard rate for existing QFs (at the time of contract renewal) and QFs that are 5 MW and smaller which includes the full avoided cost capacity rate, one of Staff’s proposed energy options and the fixed ICE. Making the standard offer rate available to existing QFs and QFs that are 5 MW and smaller aligns with Staff’s Option 1 for capacity purchases.” See Exhibit A-3

DTE has proposed that “[t]he rate so determined will apply to facilities with a capacity of 100 kW or less” and that “[t]he rate for facilities having a capacity over 100kW up to 20MW will be made under negotiated agreement.” Proposed Exhibit A-6, Rate: B.1.b. 100 kW cap is the minimum size required under PURPA. See, 18 CFR § 292.304(c) (1). PURPA provides that the standard offer may be made available for purchases from QFs greater than 100 kW. 18 CFR § 292.304(c) (2). The Commission, like other state public utility regulatory commissions, has discretion to establish standard rates for QFs larger than 100 kW. For example, the following states have the following QF capacity caps:

- California short-term and long-term standard offer contract available to QFs of 20 MW or less;

- Oregon and Utah standard offer contracts are for 10 MW or less,

- Washington State has a 5 MW threshold; and

- North Carolina, some standard offers are available to small hydro and waste–to-energy QFs of 5 MW or less.

According to the information contained in the TAC report(Appendix B) all twelve of the QFs currently under contract with DTE have capacities above DTE's proposed 100 kwh standard office cap. The same information shows that five of the twelve current DTE QF s have a capacity below Staff's proposed 5 MW cap*. Id.*

H. <u>PURPA QF Contracts</u>

FERC rules specifically allow a QF the option to provide energy or capacity on an "as available" basis or pursuant to a "legally enforceable obligation for the delivery of energy or capacity over a specified term." Specifically, 18 CFR 292.304(d) provides:

> Each qualifying facility shall have the option either:
>
> (1) To provide energy as the qualifying facility determines such energy to be available for such purchase, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or
>
> (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (i) The avoided costs calculated at the time of delivery; or
> (ii) The avoided costs calculated at the time the obligation is Incurred.

FERC has stated that Section 292.304(d) (2) gives a QF the right to establish a fixed contract price for its energy and capacity at the outset of its obligation over a specified term. See, Order No. 69, 45 Fed Reg at 12,224-12,225. FERC Order 69 provides that a QF is entitled to payments when it can make a legally enforceable commitment that would allow a utility to "defer or cancel construction of new generating units." 45 Fed Reg at 12,225.

FERC order 69 also provides that "[a] facility which enters into a long term contract to provide energy or capacity to a utility may wish to receive a greater percentage of the total purchase price during the beginning of the obligation." 45 Fed Reg 12,224 FERC Order 69 also provides in pertinent part:

> In order to defer or cancel the construction of new generating units, a utility must obtain a commitment from a qualifying facility that provides contractual or other legally enforceable assurances that capacity from alternative sources will be available sufficiently ahead of the date on which the utility would otherwise have to commit itself to the construction or purchase of new capacity. If a qualifying facility provides such assurances, it is entitled to receive rates based on the capacity costs that the utility can avoid as a result of its obtaining capacity from the qualifying facility.
>
> 45 Fed Reg at 12,225

I. <u>QF Differentiation</u>

FERC has recognized the value of differentiating between QFs depending on their supply and technology characteristics (see 18 CFR § 292.304(c)(ii)), QF's, such as hydroelectric power plants, biomass plants and waste-to-energy facilities are considered "baseload" facilities, because these facility's constant rate of electric production which may be at a lower cost relative to other production facilities.

J. Post PURPA Considerations

Since 1978 basic PURPA mandates regarding utility purchases are essentially unchanged. Rates for purchases must be "just and reasonable to the electric consumer of the electric utility", "in the public interest" and not discriminate against qualifying small power production facilities or qualifying cogeneration facilities (QFs). PURPA does not require an electric utility to pay more than its "avoided cost" for purchases from QFs. Despite the continued applicability of these and other basic PURPA provisions, there are a number of Post PURPA changes the Commission should consider when reviewing new avoided cost methodologies:

1) The competitive wholesale energy market and the creation of the Midcontinent Independent System Operator, Inc. (MISO)

2) The Energy Policy Act of 2005, FERC mandatory QF purchase obligation exemption. (On October 26, 2009 FERC granted DTE's exemption application which terminated the DTE's mandatory purchase obligation for QFs with a net capacity greater than 20 MW).

3) The enactment of 2008 PA 286 which:

- Allows retail electric choice for alternative electric suppliers in large utility service territories for up to 10 percent of utility sales.

- Requires a five year phase in for cost of service retail rates; and

- Creates a Certificate of Need approval process for larger capacity additions and can be used to evaluate the need for capacity by a utility as well as the least cost options required to meet that need through an Integrated Resource Plan (IRP).

2 TR 303-307

III.

POSITION OF THE PARTIES

A. DTE

DTE presented testimony from three witnesses: James R. Padgett. B. S.Chem.E., State Government Affairs Director, DTE Energy Corporate Services, LLC.; Laura K. Mikulan. B. S. Chem.E. Supervisor Professional Integrated Resource Planning (IRP); and Timothy A Bloch, B.S.M.E. Principal Financial Analyst. Regulatory Affairs, DTE Energy Corporate Services, LLC.

Mr. Padgett testified regarding the avoided costs information requested by the Commission in its May 3, 2016 Order Specifically, Mr. Padgett testified regarding the following PURPA related avoided costs subjects:

1) Procedural background 2 TR 298-301
2) PURPA Requirements and History 2 TR 301-307
3) Energy and Capacity Payments 2 TR 307-308
4) Avoided Cost Methodologies 2 TR 308-313
5) Standard Offer 2 TR 313
6) Renewable Energy Credits (RECs) ownership 2 TR 313-314
7) Contract Approvals 2 TR 314-315

Mr. Padgett testified regarding the policy and technical considerations used by DTE to develop the avoided cost calculation methods referenced in the Commission's order. See 2 TR 307-313. Mr. Padgett also provided testimony regarding DTE's recommended alternative avoided cost methodology. DTE believes that its alternative is the only methodology that properly calculates its avoided costs. Id.

Mr. Padgett testified that because DTE has only four PURPA contracts which will expire before 2030, DTE's general focus in the TAC, and in his testimony, is DTE's future capacity and energy needs and any new PURPA QF contract issues. See Exhibit 3 Appendix B for full listing of DTE's PURPA contracts.

Mr. Padgett testified regarding DTE's reasoning that supports DTE's capacity limit for the standard offer tariff. See 2 TR 313.

Mr. Padgett also testified regarding relevant Michigan regulatory changes that have occurred since the Commission originally addressed avoided cost determinations. Mr. Padgett testified that, given significant post PURPA changes DTE agrees with the Commission that a new avoided cost review is needed. Mr. Padgett testified that there are five post PURPA changes the Commission should consider when setting new avoided cost rates:

1) The existence of the Midcontinent Independent System Operator, Inc. (MISO) and the emergence of their competitive wholesale energy market.
2) The passage of the Energy Policy Act of 2005 and subsequent FERC approval for DTE Electric on October 26, 2009 which terminated the DTE's mandatory purchase obligation for qualifying facilities with a net capacity greater than 20 MW.
3) The passage of 2008 PA 286 which provides for retail electric choice for alternative electric suppliers in large utility service territories for up to 10 percent of utility sales.
4) The passage of 2008 PA 286 which required a five year phase in to achieve retail rates equal to the cost of service.
5) The passage of 2008 PA 286 which created a Certificate of Need approval process for larger capacity additions and can be used to evaluate the need for capacity by a utility as well as the least cost options required to meet that need through an Integrated Resource Plan (IRP).

2 TR 303-307

Laura K. Mikulan's testimony provides DTE's proposed avoided cost methodology calculations for new and future renewals of PURPA contracts and DTE's 5 year capacity Projections. She sponsored the following exhibits:

- Revised A-1 DTE Electric's Preferred Method: "Combined Cycle Gas Turbine"
- (CCGT) Avoided Cost,
- A-2(Corrected) Calculation of the CCGT Capacity Component,
- A-3 Staff Method: Hybrid Proxy Plant Method,
- A-4 Transfer Price Method developed under 2008 PA 295,
- A-5 DTE Capacity Resource Plan.

See 2 TR 27-65

Ms. Mikulan testified that DTE's avoided cost methodology is based on the following principles.

1) The determination of capacity and energy costs for an avoided plant must be based on the capacity, O&M, and energy costs of the Natural Gas Combined Cycle proxy plant. For this reason, it is inappropriate to develop avoided cost methods that arbitrarily combine MISO pricing with unrelated capacity costs.

2) Capacity and energy purchase contracts must be adjusted to reflect the various performance and dispatchability differences between the avoided plant and the PURPA QF. 2 TR 36

Ms. Mikulan further testified that based on 2016 Energy Cost value, the avoided cost using DTE's preferred method is shown in the table below by type of technology:

Type of Technology	**Capacity Cost**	**Energy Cost**	**Capacity + Energy Cost**
	¢/kWH	¢/kWH	¢/kWH
Hydro	2.70¢	2.04¢	4.74¢
Biomass	2.04¢	2.04¢	4.08¢
Landfill Gas	1.81¢	2.04¢	3.85¢
Solar	3.78¢	2.04¢	5.82¢
Wind	0.78¢	2.04¢	2.82¢

2 TR 39

Ms. Mikulan testified that the values in the above table are based on a CCGT with a 30 year life. The actual capacity payments will be based the actual QF project characteristics as explained by Mr. Padgett. Id.

Exhibit A-5 shows DTE's forecasted capacity position from 2017 through 2021. The required capacity purchases shown on line 27 are negative in years 2017 through 2021, indicating that DTE projects a "long" capacity position or have adequate supply in these years. Therefore, DTE believes that it would only be required to pay a QF only the energy component during the years 2017 through 2021. 2 TR 40.

Ms. Mikulan testified that DTE's capacity needs could change due to the following:

- Updates to the load forecast,
- Changes to MISO reserve margin calculation methodology,
- Unit UCAP changes, or
- Early unit retirements.

DTE's capacity updates would be provided in its resource plan contained in DTE's PSCR annual plan case. 2 TR 40-41.

DTE witness Bloch testified regarding DTE's proposed tariff for QF's. Mr. Bloch sponsored Exhibit A-6 Proposed Tariff Sheet - Standard Contract Rider No.5. DTE Exhibit A-6 is DTE's proposed Standard Contract Rider No. 5 titled "Small Power Production and Cogeneration Facilities 20MW and Smaller". DTE's proposed tariff combines existing Standard Rider No. 5, titled "Cogeneration" and Standard Rider No. 6, titled "Small Power Producing Facilities" into one tariff. The proposed tariff provides the terms and conditions under which DTE will purchase electricity from cogeneration QFs and small power production QFs up to 20MW. DTE's proposed tariff includes updates required due to changes in Federal Regulations and the removal of DTE's Optional Standby Rate. See 2 TR 350-361.

Mr. Bloch testified that DTE's proposed tariff is consistent with the following policy considerations discussed by DTE witness Padgett:

1) Passage of the Energy Policy Act of 2005 and subsequent FERC approval of DTE's application for a waiver mandatory purchase obligation for QF's with net capacity greater than 20 MW. A 20 MW size limit was added to the availability section of the tariff.

2) Capacity and energy purchase agreements under the standard offer tariff is limited to when DTE needs capacity.
3) Tariff availability has also been changed to indicate the tariff is only available to DTE full service customers. Id.

Mr. Bloch testified that he changed the energy only sales sections of the proposed tariff. DTE's current Rider 5 & Rider 6 tariff language for energy only sales sets the rate based on the forecasted average incremental cost of energy. DTE currently defines the forecasted incremental cost of energy under the Midcontinent Independent System Operator (MISO) market, for energy only purchases, as "the day-ahead MISO locational hourly marginal energy price for DTE appropriate load node". Id.

Mr. Bloch testified that DTE removed the optional standby rate from Rider 5 & 6 because DTE has never had any customer taking this service and DTE has no cost support for the option. DTE customers will receive standby service under DTE's current rider No. 3. Id.

DTE argues that it does not have any imminent problems involving DTE's current PURPA contracts. DTE currently has one PURPA contract that expires in 2023 and four PURPA contracts that will expire before 2030. 2TR 300. DTE believes the Commission's avoided cost review should consider significant changes in the post PURPA regulatory environment and limit the number of regulatory burdens placed on DTE. Brief p 11.

DTE believes that any avoided cost proposals or determinations which do not consider the current post PURPA regulatory environment would result in DTE overpaying for QF generation and would be contrary to PURPA's just and reasonable and in the public interest requirements.

1. DTE's Recommended Avoided Cost Method

DTE witness Padgett testified that DTE's avoided costs method is based on a Natural Gas Combined Cycle (NGCC) plant. 2 TR 311 .This is the type of plant DTE would most likely build when DTE has a capacity need and the type of plant or part of a plant that would be avoided or delayed if DTE entered into new QF contracts. DTE also believes that if it does not need capacity to serve its full service retail customers then it should only be required to purchase QF energy at DTE's incremental cost of energy. DTE argues that when it does not need capacity its avoided energy cost is the wholesale electric market spot price for energy or LMP in the MISO wholesale energy market. 2 TR 312, Brief p 13.

In summary DTE believes the following:

- A NGCC plant is the type of capacity that will be "incremental" and "avoided" when DTE purchases QF capacity;
- Capacity payments must be based on the actual QF project characteristics and DTE's avoided cost at the time; and
- Capacity payments are only required when DTE requires capacity.

2 TR 39; 307, 322

2. Other Avoided Cost Methods

DTE argues that DTE's methodology "is the only method that properly calculates DTE Electric's avoided costs." 2 TR 35. DTE believes that no other avoided cost method results in DTE's PURPA "incremental" or "but for" avoided costs.

3. DTE Rejects Staff's Hybrid Proxy Plant Method

Pursuant to the Commission's order in this matter DTE prepared Exhibit A-3. Witness Mikulan testified regarding DTE's HPPM calculation. See 2 TR 40, 310; Exhibit A-3.

DTE rejects Staff's and the TAC reports recommended Hybrid Proxy Plant Method (HPPM) because DTE believes the HPPM does not accurately represent DTE's avoided costs. Specifically DTE believes the HPPM:

- Arbitrarily assigns fixed cost the variable energy component which significantly over or under compensates for the total energy and capacity value; and

- Is overly complex for no identifiable value.

DTE argues that HPPM is overly complex because it requires the calculation of three components to calculate the rate – the energy, capacity, and ICE components with three energy component options. DTE witness Padgett testified that each energy option includes an ICE adder which DTE believes transfers some capacity costs to the energy rate resulting in partial QF compensation for capacity costs in the energy payment during when DTE may not need capacity. 2 TR 307-310.

DTE also rejects Staff's recommendation for a single cycle combustion turbine (CT) as the capacity proxy plant because DTE believes it has adequate peaking capacity for the foreseeable future. Id. DTE argues that it acquired two plants last year and is not projecting any future capacity needs. In support of DTE's capacity positions DTE provided Exhibit A-2 and A-5.

DTE Exhibit A-2 (Corrected) breaks out the capacity component of DTEs avoided costs. See Mikulan Testimony 2 TR 38-39. Exhibit A-5, provides DTE's Capacity Resource Plan for 2017-2021 which shows that DTE has no need for capacity in the next 5 years.

4. <u>DTE Rejects the Transfer Price Method</u>

Pursuant to the Commission's order in this matter, DTE prepared Exhibit A-4. DTE witness Mikulan testified regarding DTE's TPM calculation 2 TR 40, 311; Exhibit A-4.

DTE argues that the Transfer Price Methodology (TPM) does not reflect DTE's actual costs. DTE witness Padgett testified that the TPM:

> "…is not a cost-based method for determining DTE Electric's avoided costs The Staff's transfer price method utilizes a transfer price concept for the energy component that was developed consistent with the methodology approved by the Commission as a result of 2008 PA 295. The Staff Transfer Price method was discussed in TAC meetings and is based on a levelized cost of a natural gas combined cycle. The method develops a projected cost for each year based on assumed inflation rates, projections for material costs, labor costs, and natural gas price forecasts…"
>
> 2 TR 310-311, Brief p 16

DTE argues that the TPM is flawed because:

- Capacity payments are not discounted to reflect the true value of the intermittent capacity value recognized in MISO through an ELCC adjustment;

- The energy component of the avoided cost is based on a 'snapshot in time' price forecast given the historical volatile nature of the gas market which is then levelized over a lengthy period of time; and

- Customers would pay higher avoided costs for energy over the applicable contract term.

Id.

DTE witness Padgett testified that the energy payment should be based on the actual avoided cost of energy using a market based gas price calculation. DTE argues that the avoided costs calculated using the TPM do not reflect DTE's actual avoided costs. Id.

DTE concludes that the use of either the HPPM or the TPM would result in avoided costs that are higher than DTE's actual avoided costs calculated using DTE's preferred avoided cost method. DTE argues that the Commission's adoption of either the HPPM or TPM would be inconsistent with the requirements of PUPRA and would result in avoided costs which are not just and reasonable to DTE's customers nor in the public interest. Brief p 16.

5. DTE Supports Biennial Avoided Cost Filings

DTE believes the continued use of biennial avoided cost filings would;

- Provide a mechanism to keep DTE's avoided capacity and energy costs current;
- Identify DTE's capacity needs over a subsequent 5 year period; and
- Would allow the Commission and potential QFs access to updated avoided cost information.

2 TR 306

DTE argues that it's "biennial filing" would include DTE's projected capacity needs identified in DTE's latest PSCR plan case 5-year forecast. DTE believes that this approach would eliminate duplicative contested case proceedings and would allow for the use of one set of data. DTE does not support a 10 year planning because it believes that projecting capacity needs over a 10-year or longer period would:

- Increase uncertainty; and

- Require imprudent capital and other resources costs which would be passed on to DTE customers.

Id.

6. QF Capacity Payments when DTE has no Capacity Needs

DTE argues that it should only be required to pay for QF capacity when it projects a capacity need in the next 5 years. DTE believes that PURPA does not require DTE to prospectively pay for new QF capacity when DTE does not need capacity to serve its full service retail customers. DTE further argues that if DTE has or is projecting that it has adequate capacity to serve its retail customers, then DTE's obligation to purchase from a QF is limited to DTE's avoided energy cost. 2 TR 307 Brief p. 17. In support of this position DTE witness Padgett testified:

> "PURPA defines avoided cost as:
>
> The **incremental** costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility **would** generate itself or purchase from another source." 18 CFR 292.101(b) (6) (emphasis added)"
>
> 2 TR 307

DTE argues that a cost is not "avoided" and is neither "incremental" nor "would" be generated if it is the result of a subsidy, theory, policy or speculation about projected future needs. DTE argues that its current Commission approved avoided cost is based on actual avoided cost methodology using the DTE Belle River generation unit.

DTE believes that when it does not need QF capacity, to serve its full service retail customers, DTE should only be required to purchase QF energy at DTE's incremental energy cost. DTE witness Padgett testified that when DTE does not need QF capacity DTE's avoided energy cost is the wholesale electric market spot price for energy or LMP in the MISO wholesale energy market. 2 TR 312 Brief p 18.

7. Standard Offer Tariff Limit

DTE supports the current design capacity of 100kW or less standard offer tariff limit. DTE argues that its current 100kw cap:

- Complies with PURPA;
- Has not posed any known problems with existing QF s; and
- There are no compelling regulatory reasons to create additional burdens on DTE in the current regulatory environment.

2 T RR 308, 313

DTE's proposed standard offer tariff may be found in Exhibit A-6 (see Exhibit A-6 Proposed Tariff Sheet – Standard Contract Rider No. 5). Mr. Bloch testified regarding the necessary changes and updates to the existing DTE Riders. 2 TR 356-357

8. 18 CFR 292.304 Factors should be Subject to Negotiation

DTE indicated that it will consider the principles and factors discussed in 18 CFR 292.304 when determining applicable QF capacity and energy rates for QF purchases. DTE believes that, due to variability in project circumstances and capabilities, the application of the factors should be negotiated during the contract negotiation process. 2 TR 308 Brief p 18.

9. QF Contract Length should be Negotiated

DTE believes that the length of QF contracts should be left to negotiation process. Mr. Padgett testified:

> "…the rate the Company should pay a QF is affected by the term of the agreement. The rates DTE Electric pays for power from QFs must be just and reasonable to the electric consumer of the electric utility. For this reason, DTE Electric believes that arbitrarily setting a contract length as part of this methodology review is not in the interest of either party and should be left to the negotiation process. For expiring contracts, the contract life

> should again be left to the negotiation process so the financial status and needs of the project can be reviewed and compared against the applicable market conditions. Other considerations such as the utilities [sic "utility's"] relevant avoided cost at the time of contract renewal and ongoing need for the project will likely be more significant factors than contract life when considering renewal."
>
> 2 TR 312

10. Renewable Energy Credits from QF Purchases

DTE argues that it should receive the value of RECs and that the Commission should not leave the disposition of Renewable Energy Credits (RECs) to future negotiations. DTE believes that if a QF generates RECs, then the RECs are part of the total QF product value that DTE is required to purchase. Because PURPA requires DTE to purchase generally renewable QF energy and capacity DTE believes that it should receive RECs. DTE believes that if it does not receive the REC's with a QF purchase then its full service customers would have to pay extra for RECs. 2 TR 313-314. Brief p 19.

11. DTE Recovery of PURPA QF Purchases through MCL 460.6j

DTE argues that because it has a PURPA obligation to purchase capacity, or energy, or both, from a QF then DTE has the right to recover those costs from DTE's retail electric customers. MCL 460.6j, as amended, provides that the Commission may allow DTE to recover QF contract charges. DTE believes that this requirement would not apply to QF contracts 100kW and smaller, because those contracts are part of a Commission-approved standard offer tariff. MCL 460.6j distinguishes between actual contract approvals and the power supply reconciliation process. DTE believes that, the Commission's past practice, requires all necessary contract approvals to occur outside a power supply plan, reconciliation, or general rate case, and Commission approval prior to when actual purchased power expense recovery is required by DTE. 2 TR 314-315, Brief p 19.

12. Alternative Energy Suppliers should be Required to Comply with PURPA

DTE argues that the Commission should require Alternative Energy Suppliers (AES) to comply with PURPA and that the failure to do so would discriminate against DTE. Brief p 19-20

PURPA defines an 'electric utility' is to include 'any person, state agency or federal agency, which sells electric energy.' PURPA Section 3(4), 16 U.S.C. Section 2602(4) (2012). DTE argues that given this definition, PURPA's QF purchase obligation is not limited to the interconnecting utility, but includes any entity that sells electric energy. DTE argues that because all AESs sell electric energy, they are 'electric utilities' subject to PURPA." Brief p 20, 2 TR 337. DTE witness Padgett testified that "not requiring Alternative Electric Suppliers (AESs) to abide by PURPA and purchase from and sell to their generation customers would discriminate against DTE. DTE believes the Commission should confirm that under PURPA, AESs are "electric utilities" and have a PURPA QF purchase obligation from QFs owned by their customers.

B. Staff

Staff presented testimony from three witness:

- Julie K Baldwin, B.S. Chem E., Manager Renewable Energy Section, Electric Reliability Division;
- Jesse J. Harlow, B.S.E, Public Utilities Engineer , Renewable Energy Section, Electric Reliability Division; and
- Kevin S Krause, B.S. N.E, M. N.E, M. B. A. Auditor, Renewable Energy Section. Electric Reliability Division.

Ms. Baldwin testified regarding Staff's recommend changes to DTE's Proposed Tariff Sheet – Standard Contract Rider No. 5 filed by DTE witness Bloch as Exhibit A-6. See 2 TR 72 Ms. Baldwin sponsored Exhibit S-1 (JKB-1) MPSC Staff Proposed Standard Offer Tariff and Exhibit S-2 (JKB-2) DTE Discovery Response STDE-1.1.

Ms. Baldwin recommends the Commission review DTE's avoided cost on a biennial basis. 2 TR 72- 72-73. She also recommends the following revisions to the standard offer tariff:

- Limit the tariff's applicability to the standard offer tariff qualifying facility (QF) size cap; 2 TR 73.

- Set the standard offer tariff QF size cap (in the range of 1 MW to 5 MW) according to the capacity need of the utility during the succeeding two years and the PURPA 10-year planning horizon; 2TR 73-76.

  - Set the standard offer term at 5, 10 or 15 years at the QF's option; 2 TR 76-77.

  - Set the standard offer rates based on Staff's avoided cost methodology. 2 TR 77-79

Mr. Harlow testified regarding Staff's proposed avoided cost methodology. See 2 TR 100-107. He sponsored the following exhibits:

- Exhibit S-3 (JJH-1) MPSC Staff's PURPA Technical Advisory Committee *Report on the Continued Appropriateness of the Commission's Implementation of PURPA*;

- Exhibit S-4 (JJH-2) Pages 1-3, MPSC Staff's Proposed Avoided Cost Methodology and Calculation;

- Exhibit S-5 (JJH-3) Pages 1-3, MPSC Staff's Variable Natural Gas Combined Cycle Plant (NGCC) Cost for Energy Component; and

- Exhibit S-6 (JJH-4) Ten Year Locational Marginal Pricing (LMP) Projections.

Mr. Harlow testified that Staff's proposed avoided cost method is the most reasonable method because it combines the most appropriate components of the market and traditional proxy plant avoided cost calculations. Staff's proposed method energy component addresses DTE's concerns regarding the creation of MISO energy market and is consistent with Staff's proposed method in the Consumers Energy Company avoided cost case U-18090. Mr. Harlow testified that the avoided cost method for DTE and Consumers Energy Company should be consistent when practicable. 2 TR 97-98.

Staff's proposed avoided cost method is discussed in detail in the TAC report. See Exhibit S-3 (JJH-1).

Mr. Krause provided testimony regarding PURPA, avoided costs, and avoided cost methodologies. See 2 TR 84-89. Mr. Krause also provided testimony regarding PURPA QF rates. See 2 TR 89-91. Mr. Krause did not sponsor any exhibits.

DTE's preferred avoided cost method calculates avoided energy costs based on a natural gas combined cycle (NGCC) proxy plant variable cost consisting of fuel commodity and delivery cost times heat rate plus the variable operating cost. Exhibit A-3. 2 TR 35-36. Staff indicated in its brief that DTE's proposal would not achieve the purpose and goals of PUTPA because DTE's method would not encourage DTE to purchase from QFs at its non-discriminatory avoided cost rate. 2 TR 76-77, 84-85, 90. Brief p 3. Staff believes that PURPA section 210 gives QFs the right to long-term fixed rates for energy and capacity. Id.

Staff argues that the energy component of the avoided cost method the Commission adopts should provide a QF with:

- A choice between locational marginal pricing (LMP), a forecast LMP or a forecast based on a Natural Gas Combined Cycle(NGCC) Plant; and

- A standard contract term of 5, 10 or 15 years for QF with a design capacity of 1MW or less at the QF's option.

Brief p 3

Staff argues that the capacity component of the avoided cost method adopted by the Commission should use a Natural Gas Combustion Turbine (CT) value, similar to the MISO Cost of New Entry method (CONE). Staff believes that large capacity QFs should be allowed to negotiate contracts with DTE which calculate avoided costs based on the Commission's approved avoided cost methodology. Staff argues that its avoided cost proposals, if adopted by the Commission, would be consistent with PURPA's goals by encouraging renewable resources and cogeneration for wholesale power supply. Brief p 4, See 2 TR 85-86.

1. <u>Staff's Hybrid Proxy Plant Method</u>

Staff proposes the Commission adopt Staff's Hybrid Proxy Plant Method (HPPM). Staff's HPPM is the same method Staff recommended following the Commission's PURPA TAC meetings. See Staff Exhibit S-3. Staff's HPPM combines a proxy unit methodology for capacity and a market based pricing methodology for energy. Staff argues that its HPPM meets the requirement of FERC Order 69 and 18 CFR § 292.101(b) (6). 2 TR 100-102; Order 69, 45 Fed. Reg. at 12,225. Brief p 4. Staff's witness Harlow provided detailed testimony regarding the HPPM. See 2 TR 100-107. Staff's HPPM avoided capacity rate is based on the avoided cost of a CT plant. Staff argues that a CT plant is a reasonable proxy for DTE's avoided capacity costs. Brief p 4. Mr. Harlow testified that if DTE has a capacity need it would more than likely build a CT plant. These plants can be built quickly at less cost than other types of generation and may be turned on and off depending on the need for power. 2TR 103.

Staff also argues that the HPPM's use of MISO zonal resource credits (ZRCs) is reasonable. ZRCs would only be applicable to non-baseload energy. Staff believes that ZRCs are a valuable measure of capacity because MISO uses ZRCs in evaluating DTE's capacity. 2 TR 98. MISO's ZRCs include the effective load carrying capability (ELCC) based on historic availability during peak for intermittent generation.

Staff argues that if DTE has any capacity needs during a 10-year planning horizon then DTE must pay a QF for its capacity. Brief p 5. According to Staff's proposal existing QFs will be treated differently from new QFs. When an existing QFs renews it QF contract, the contract will include a capacity payment at the full standard rate capacity. The capacity payment will be included regardless of DTE's capacity need during the PURPA 10-year planning horizon. 2 TR 99.

Staff proposes that for new QFs, not part of DTE's portfolio, if DTE's capacity need over the 10-year planning period is fully met, QFs would be compensated at the cost of MISO's Planning Resource Auction (PRA) 2 TR 99.

Staff disagrees with DTE that the PRA is an adequate pricing methodology even if its capacity need is reduced for existing QFs that have already been taken into account in DTE's baseload. Staff argues that the PRA:

- Is not representative of the value of long-term capacity in a free market;
- Is not intended as a mechanism for recovery of a generation plants' capacity costs;
- Provides a balancing function to make up small capacity shortfalls in the upcoming or following year; and
- Is not intended to support resource investment decisions.

2 TR 102

Because QF's offer energy and capacity over the long-term Staff believes the PRA would not satisfy the purpose of PURPA and thus is not an adequate avoided cost measure. Staff proposes that, because the capacity of QFs with existing contracts has already been taken into account by DTE, the QFs should be compensated at the time of contract renewal at Staff's proposed Modified Proxy Plant methodology. 2 TR 100.

Staff recommends QFs should have the option of one of three avoided energy rate choices which would be applicable for the entire period of the contract. 2 TR 104-105.

Staff's proposed energy payments options are:

(1) Locational marginal price (LMP),

(2) A forecasted LMP over the contract period, or

(3) A proxy method based on the forecasted variable cost of a natural gas Combined cycle plant (NGCC).

Brief p 6

Staff believes a NGCC is a reasonable energy value proxy because utilities are currently building an NGCC due to its efficient use of natural gas. A NGCC is built to provide cheap energy. Staff did not select a CT plant as an energy proxy because a CT would generally built to provide cheap capacity. See Exhibit S-4.

For option three Staff used the variable cost component of the model used for calculating transfer prices to determine the avoided energy price. 2 TR 105. Staff updated this calculation using DTE provided data. Staff's proposed energy options also include a fixed investment cost attributable to energy (ICE). The ICE is based on the difference in fixed costs between a CT and NGCC. 2 TR 101. Exhibit S-4. This difference is paid on a volumetric basis and is added to the energy payment.

Staff points out in its brief that Staff's recommendations, and this proceeding, only apply to QFs that produce equal to or less than 20 MW. Staff also points out that standard offer contracts would be filed by DTE through an *ex parte* proceeding. 2 TR 144. Non-standard offer contracts, negotiated between DTE and a QF, based on the Commission-approved avoided cost methodology could also be filed as an *ex parte* proceeding. 2 TR 158.

2. Staff's Standard Offer Tariff Recommendations

Staff proposed revisions to DTE's standard offer tariff are provided in Exhibit S-1. Staff's recommends the following:

- A methodology based on the utility's capacity needs to determine the standard offer tariff QF design capacity size cap;
- Standard offer contract length of 5, 10 or 15 years;
- Credit for line loss savings according to the location of the QF on DTE's distribution system;
- Three available options to the QF for energy payments,
- Capacity payment based on Staff's avoided capacity cost calculation;
- Renewable Energy Credits (RECs) are transferred to DTE as part of the standard offer;
- Commission review the standard offer tariff every two years as part of the avoided cost biennial review process;
- Commission review and consider standard offer contracts for approval on an ex parte basis.

The standard offer tariff filed by DTE limits the tariff' to QFs that have a capacity of 100 kW and less. PURPA requires the standard offer be made available to QFs with a design capacity of 100 kW and less. Staff proposes the following standard offer tariff cap.

If DTE has capacity need during its PURPA 10-year capacity planning horizon, then Staff recommends:

- 1 MW Standard Offer size cap when the utility needs 0 – 100 MW during the succeeding two years,
- 2 MW cap when up to 200 MW is needed,
- 3 MW cap when up to 300 MW is needed,
- 4 MW cap when up to 400 MW is needed; and
- 5 MW cap when more than 400 MW is needed.

Brief p 8, 2 TR 75

3. <u>Standard Tariff Cap</u>

Staff proposes a standard offer tariff a size cap of 1 MW for Standard Offer Rider eligibility. See Exhibit S-1. Staff agrees with the City of Ann Arbor (CAA) that DTE's proposed 100 KW standard offer cap complies with PURPA but is very low. 2 TR 283-284.

4. <u>Standard Offer Tariff Contract Length</u>

Staff recommends that QFs have standard offer tariff contract term options of 5, 10 or 15 years. Staff witness Baldwin testified that existing PURPA contracts, and recent Act 295 contracts, are typically 5 years or longer. 2 TR 76-77. Staff does not agree with DTE's recommendation that does not include any contract term length or any ability to forecast costs. Brief p 9. Staff's believes that PURPA allows a QF to obtain a contract with a forecasted rate over an appropriate contract term. See 18 CFR § 292.304(d) (2).

Staff argues that the short QF contract term proposed by DTE would not be consistent with FERC rules. Section 210 of PURPA, 16 USC § 824a-3, and FERC's regulations require the Commission, a state regulatory authority, to encourage cogeneration, small power production, and small geothermal production for wholesale power supply. Staff argues the Commission has the authority to determine appropriate specific terms of the must purchase obligation. "[A] state may take action under PURPA only to the extent that that action is in accordance with the Commission's rules." *Allco Renewable Energy Ltd*., 146 FERC ¶ 61107 (Feb. 20, 2014); See also *FERC v Mississippi*, 456 US 742, 751 (1982); 16 USC § 824a-3(f).

Staff argues that there is no dispute that PURPA regulations at 18 CFR 292.101(b)(6) define avoided costs as including a capacity or energy charge or both. There is a dispute whether avoided costs can be forecasted as well as the period or term upon which forecasted avoided costs should be based for the standard offer. Staff argues that DTE's proposed standard QF contract terms, without the option of any guaranteed contract length, would not:

- Compensate QFs for their capacity contributions to DTE's system; and
- Would violate FERC regulations standard contract provisions.

FERC's must purchase obligation regulations at 18 CFR § 292.304(d) provide:

> Each qualifying facility shall have the option either:
>
> (1) To provide energy as the qualifying facility determines such energy to be available for such purchase, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or
>
> (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (I) The avoided costs calculated at the time of delivery; or
>
> (ii) The avoided costs calculated at the time the obligation is incurred.
>
> Brief p 12

Staff argues that if a QF contractually agrees to make its capacity available when DTE would otherwise construct a new generation facility then the QF is entitled to avoided costs based on the construction costs of a new facility. Staff relies upon FERC Order 69 which provides in pertinent part:

> "If a qualifying facility provides [contractual or other legally enforceable assurances that capacity will be available to displace future new capacity], it is entitled to receive rates based on the capacity costs that the utility can avoid as a result of its obtaining capacity from the qualifying facility."
>
> *See, Regulations Implementing Section 210 of the Public Utility Regulatory Policy Act of 1978,* Order No. 69, 45 Fed. Reg. 12,214, 12,225 (Feb. 25, 2980).

Staff believes that the Commission has the authority to determine what a "specified term" is under 18 CFR § 292.304(d).

Staff further argues that DTE proposed no QF contract term would be discriminatory towards QFs and would not provide QF compensation for capacity consistent with FERC order 69. FERC order 69 provides in pertinent part:

> "[If a QF] offers energy or sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, the rate for such a purchase will be based on the avoided capacity and energy costs."
>
> Order 69, 45 Fed. Reg. at 12,226; See 2 TR 70

Staff argues that because QFs have the long-term ability to defer the utility's construction of new generating units, QF contract terms should allow QFs to be compensated for their ability to meet DTE's capacity needs. 2 TR 144, 2 TR 102.

DTE will only defer or cancel future capacity projects if willing QFs are able to enter into long term contracts to provide capacity. 2 TR 287. Brief p 13.

Staff rejects DTE's argument that a QF contract based on forecasted costs does not provide a fixed term during which power would be available. Without a firm commitment DTE believes that it could not cancel planned generation.

Staff argues that DTE's proposal would be contrary to FERC's legally enforceable obligation rule's requirement to compensate QF for capacity by allowing DTE to avoid paying a price to defer or cancel new capacity. An avoided cost methodology is only effective if the contract's length or term specifies that forecasted costs shall be used or the cost at the time the energy is used, at the choice of the QF at the time of entering into the agreement. Brief p 14.

Staff argues that PURPA, section 210, 16 USC § 824a-3, allows a QF to choose forecasted costs, e.g. costs calculated at the time the "obligation is incurred." Staff rejects DTE's proposal to offer QFs contracts with indefinite or shortened terms because DTE's proposal is:

- Inconsistent with FERC's PURPA regulations because QFs, and
- Would deprive QF of a contract price based on prices calculated at the time the contract is executed.

Id.

FERC rule 18 CFR § 292.304(d) (2) (ii) provides a QF shall have the option to enter into a contract or other obligation to sell both energy and capacity based upon the avoided costs calculated at the time the obligation is incurred. Rule section 292.304(d) provides a QF also has the unconditional right to choose whether to sell its power 'as available' or at a forecasted avoided cost rate pursuant to a legally enforceable obligation." *Hydrodynamics Inc. et al,* 146 FERC ¶ 61,193, p 31. The cost at the time the obligation is incurred has been interpreted to mean forecasted costs.

Staff argues that DTE's proposal does not consider a QF's legal right to pricing based on avoided cost calculations that are current at the time the obligation is made. e.g. Forecasted costs over a reasonable period. DTE's proposal limits a QF contract terms so that prices paid to the QF would not be based on forecasted costs and would not be of an appropriate duration. Brief p15. Staff rejects DTE's belief that its proposal is in the best interest of ratepayers, because forecasted costs over a period of time, could benefit ratepayers or the QF, depending on whether the forecasted of actual costs favor the QF or the ratepayer. 2 TR 310-311.

Staff argues that DTE's proposal for standard contracts, without the option of long-term forecasted costs, is not reasonable, because the proposal fails to balance the QF's and DTE's rights. Id.

DTE witness Padgett testified that costs should not be based on a snapshot in time. 2 TR 310-311. Staff argues that FERC has indicated that forecasted costs are a fair option under PURPA. *Hydrodynamics Inc. et al,* 146 FERC ¶ 61,193, p 31. Staff rejects DTE's proposal because it would eliminate a QF's right to obtain pricing based on the avoided costs calculated at the time the obligation is incurred or based forecasted costs at the option of the QF.

Under § 210 of PURPA, DTE, must purchase available electric energy from cogeneration and small power production facilities that obtain QF status. According to FERC rules DTE is required to pay rates that meet the following requirements:

(1) shall be just and reasonable and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

See 16 USC § 824 (c)

FERC regulations require that the rates DTE pays to purchase QF energy and capacity reflect the costs that DTE avoids as a result of obtaining QF energy and capacity. Staff rejects DTE's argument that the spot energy market is the only appropriate avoided cost method for QF purchases.

5. Line Losses

Staff's proposes that the standard offer rider include a sentence recommending that line losses be evaluated on a case-by-case basis. 2 TR 78.Staff' argues that the standard offer tariff should include language to compensate a QF for line losses savings 2 TR 78. Staff disagrees with DTE's statement that line loss cannot be quantified and should not be included with respect to a standard offer tariff. 2 TR 52, 59-61.

6. Biennial Review

Staff proposes a biennial review process which Staff argues is consistent with 18 CFR § 292.302(b). Staff's proposal requires DTE to report avoided cost data every two years and capacity planning information for a 10 year period. 2 TR 72. Staff's biennial review proposal includes, when necessary, Commission review of the standard offer during a contested case proceeding. Staff believes that this process would allow the Commission to update DTE's standard offer cap, depending on DTE's capacity needs. Brief p 10 2 TR 72, 74-75. Staff's proposal also includes a provision that if DTE does not project a capacity need during its 10-year planning horizon before the Commission's biennial review, then DTE could file a request to adjust the standard offer to the PRA. 2 TR 75-76.

7. Renewable Energy Credits

Staff recommends DTE receive the Renewable Energy Credits (RECs) when a QF and DTE enter into a standard offer contract. Staff argues that this approach balances the interests of QFs and DTE. 2 TR 78. REC ownership would be negotiated for QFs that choose to negotiate a contract rather than to accept a standard offer contract. Brief p 10.

C. City of Ann Arbor

The City of Ann Arbor (CAA) provided testimony from two witnesses Peter Richardson B.A., J.D. and Brian Stegliz, B.A. MSE, Utilities Engineer, City of Ann Arbor.

Mr. Richardson testified regarding his analysis of DTE's proposal and provided recommendations regarding how avoided costs should be determined in order to comply with PURPA. He sponsored the following exhibits: Exhibit AA-1 (PR-1) DTE response to discovery ELPCDE–1.15, p. 6; Exhibit AA-2 (PR-2) DTE response to discovery ELPCDE-2.35; and Exhibit AA-3 (PR-3) DTE response to discovery ELPCDE–2.33

Mr. Richardson provided a PURPA and QF overview. This information is provided with other PURPA information in the background section of this PFD.

Mr. Stegliz testified regarding CAA's two hydroelectric plants. Rather than summarize his testimony regarding the history, capacity, revenues, public benefits, and CAA's past, current and future capital investments please see the following transcript pages:

- History and current capacity 2 TR 254-255
- City of Ann Arbor Capital Investments 2 TR 255-257
- Revenues 2TR 257
- Public benefits 2 TR 258-259

Mr Stegliz also provided rebuttal testimony regarding Staff's recommendation for QF contract length and RECs. 2 TR 261-263

CAA argues in its brief that the Commission's avoided cost method must:

- Be just and reasonable to DTE's customers. See PURPA § 210(b) (1);
- Be in the Public interest. See PURPA § 210(b) (1); 18 CFR 292.304(a) (1) (i);
- Be Non Discriminatory. See PURPA § 210(b) (2); see also 18 CFR 292.304(a) (1) (ii);
- Not exceed DTE's Incremental costs. See 2 TR 268;
- Provide that a QF at its option has a legal right to provide energy and capacity to DTE pursuant to a legally enforceable obligation through a long term contract. See 18 CFR 292.304(d)

Brief pp 5-14

1. <u>MISO Short Term Market Rates</u>

CAA argues that DTE's avoided cost method, which relies on MISO's short term residual market for energy or capacity values, is unjust, unreasonable, and discriminatory to QFs and violates PURPA. CAA argues that neither DTE nor the Commission may pursue low energy and capacity rates when setting DTE's "avoided cost" rate in order to achieve ratepayer savings. CAA argues that doing so would:

- Deprive QFs of DTE's full avoided cost rate,
- Be discriminatory toward QFs, and
- Violate PURPA. See PURPA § 201(b).

According to FERC's rules avoided costs rates may not exceed the utility's "full" avoided costs, CAA argues that if the Commission set rates below DTEs full avoid costs doing so would be discriminatory toward QFs and would discourage QF development. Brief p 15. FERC's rules also provide that, if a QF chooses to provide electric energy pursuant to a "legally enforceable obligation," the QF must have the option to receive the avoided costs "calculated at the time of delivery" or "calculated at the time the obligation is incurred." See 18 CFR 292.304(d) (2).

DTE's avoided capacity costs proposal uses a proxy plant rather than using MISO market values when a QF is being paid for capacity. DTE proposes "energy only" QF payments, paid at "the wholesale electric market spot price for energy or LMP in the MISO wholesale energy market." 2 TR 312. DTE's proposal would:

- Violate FERC regulations which require the QF the option to obtain forecasted energy prices, and
- Provide discriminatory energy rates.

CAA argues the MISO energy market is a spot market for residual energy and does not represent CAA's hydro projects long-term value to DTE.

Brief p 18

2. <u>DTE's Proposed Avoided Cost Method is Discriminatory</u>

COAA argues that DTE's proposed avoided costs method is discriminatory towards QFs and violates PURPA. CAA believes that DTE's interpretation of FERC regulations incremental costs is incorrect. DTE witnesses Padgett and Mikulan use of the term "incremental" in their testimony. See 2 TR 36, 2 TR 310. Both suggest that DTE believes that incremental capacity is whatever small amount of residual capacity DTE needs in addition to the long-term capacity supply it can otherwise obtain. DTE believes that the incremental cost is the lowest cost resource that can be obtained to meet DTE's residual need. CAA argues DTE's understanding is not consistent with PURPA and FERC rulings.

According to FERC the term incremental is intended to reflect the next incremental unit would be the higher cost units of the utility "The utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs." Order 69, 45 Fed Reg at 12,216.

3. DTE's Cost-Based Rates for QFs Violates PURPA

CAA rejects DTE's potions that QF rates must be cost based. DTE witness Padgett testified that "DTE Electric strongly believes that any efforts to deviate from cost based concepts in determining avoided costs for new or existing projects must be rejected." 2 TR 305. DTE objects to:

- Staff's HPPM because I "[i]t is not a cost-based method." 2 TR 308.
- Transfer Price Schedule because "[i]t is not a cost-based method." 2 TR 310.
- Staff's proposal for payment of capacity under the standard offer is that it "deviates from the cost based rate approach that utilities have been operating under since 2008 in Michigan." 2 TR 323.

CAA argues that DTE's position, would subject QFs to cost-of-service ratemaking, and would violate DTE's and the Commission's PURPA obligations. Brief p 23.

4. DTE's Capacity Proposal is Discriminatory

CAA argues that DTE's PURPA QF purchase obligation arises when a QF offers capacity with firm contractual requirements. See Order 69, 45 Fed Reg at 12,216. PURPA was enacted "to encourage cogeneration and small power production." Order 69, 45 Fed Reg at 12,215. CAA believes that once a QF can provide "sufficient legally enforceable guarantees of deliverability," then DTE must purchase both the QF's capacity and energy. Order 69, 45 Fed Reg at 12,216. See Brief p 25.

CAA rejects DTE's proposal to cease paying for capacity from existing QFs unless those facilities demonstrate to DTE's satisfaction, at a level of "substantial proof," that it's generating and protective equipment is "new or equivalent to new." 2 TR 360. CAA argues that DTE's current tariff, Standard Contract Rider No. 5, is available only to "Customers who employ cogeneration technology as an energy source and sell electric output of their cogeneration facility to the Company." Brief p 26 .CAA points out that CAA's Barton and Superior dams are hydro power facilities and not cogeneration facilities. Neither DTE's current provisions of this Rider, nor, those in effect when those contracts were last negotiated, apply to CAA's hydro QFs .CAA rejects DTE's proposal to expand its current Rider to cover cogeneration facilities, and "[f]ull service customers with on-site small power production or cogeneration facilities 20MW an smaller that seek to sell electric output from their facility to the Company." Exhibit A-6.

CAA argues that DTE's proposed tariff language which restricts QF purchases to only DTE full service customers is discriminatory and in violation of PURPA because it:

- Violates the PURPAQF must purchase obligation, and
- Creates additional burdens and hurdles for existing QFs seeking to sell their power.

Brief p 27

5. DTE's Capacity Proposal Violates PURPA

PURPA Section 210(e), exempts QFs from being treated like a regulated utility where "necessary to encourage cogeneration and small power production." CAA argues that DTE's avoided cost methodology for capacity bases the proxy payment of a natural gas combined cycle plant ("NGCC") on MISO's ZRC capacity structure to determine the amount of capacity purchased, and requires capacity pricing to be ZRC-based.

DTE witness Padgett testified that, "[c]apacity payments for QFs should be based on the ZRC value related to the technology." 2 TR 331. CAA argues that DTE's MISO's ZRC requirements, treat QF's as if is a regulated utility in violation of PURPA Brief p 28.

CAA argues that DTE's market-based methodology is based on DTE's belief that its customers should not pay more for energy and capacity than the cheapest source of residual supply. DTE witness Padgett testified:

> "[i]f the capacity value purchased from QFs is less than that recognized by MISO, the Company would conceivably need to procure additional capacity to satisfy MISO reliability requirements, and thereby unnecessarily increase DTE Electric customer costs."
>
> 2 TR 331

CAA argues that FERC has rejected DTE's lowest cost avoided cost option. CAA's witness Richardson, rejects DTE's proposal because it:

> "[t]reats all QFs like residual suppliers," and consequently does not comply with PURPA §210(d). … "DTE [does not] seek reimbursement for its own capacity at the 'intermittent capacity value recognized by the [MISO] through an Effective Load Carrying Capability (ELCC) adjustment and the performance of the generator,' as the Company has proposed for QFs."
>
> 2 TR 272

CAA argues that DTE's QF avoided cost is not consistent with DTE's avoided cost. CAA argues that DTE provided testimony before the Senate Energy and Technology Committee that DTE's generation capacity costs are 5.4 cents/kWh and estimated its fuel costs are 3.3 cents/kWh and DTE's capacity and energy, costs are approximately 8.7 cents/kWh. See Exhibit CAA-1. CAA argues that the avoided costs DTE provided to the Senate are well below the costs reported by DTE witness Mikulan. See 2 TR 272-73. CAA argues that DTE's proposed QF avoided costs are much lower than DTE's avoided costs and as a result are discriminatory and violate PURPA.

6. DTE's Avoided Cost Methodology for Energy is Unjust, Unreasonable and Discriminatory

CAA rejects DTE's proposal to pay QF's DTE's "incremental cost of energy", which DTE believes "simply the wholesale electric market spot price for energy or LMP in the MISO wholesale energy market." 2 TR 312. CAA argues that DTE's proposal does not meet PURPA's avoided cost requirements. Brief p 30. In support, CAA witness Richardson testified that not:

> "[r]equiring QFs to only receive avoided costs based upon MISO's market prices would result in discriminatory treatment of QFs, since MISO's energy and capacity markets are merely residual, short-term markets that do not reflect the Company's real avoided costs pursuant to PURPA."
>
> 2 TR 273

7. DTE's Proposed Standard Offer Contract is Discriminatory and Violates PURPA

CAA rejects DTE's argument that DTE should only be required to meet the minimum PURPA standards which allow the Commission to retain and set DTE's current standard offer at 100 kW.

CAA argues maintaining DTE's current 100 kW limit would neither encourage development of QF projects nor allow the Commission to achieve PURPA's goals. In support, CAA points to a DTE discovery response in which DTE indicated "DTE Electric historically and currently has little demand from small generators relying on QF status…." "[b]ased on our experience, the Company believes the 100 kW limit works well for its service territory." Exhibit CAA-8. CAA argues that DTE's proposed 100kw standard contract limits has failed to achieve the goals of PURPA. Therefore continuing the 100kw limit would violate the Federal requirements.

DTE's proposed standard contract provides "unless substantial proof is shown that the generator and protective equipment is new or equivalent to new." Exhibit CAA-21. CAA argues that this language is discriminatory because it treats QF's differently. Older QFs would be put out of business if DTE was allowed to refuse to buy offered capacity from a QF unless they make enormous "new or equivalent to new" capital investments in their facilities generator equipment. CAA argues that DTE's proposal is also discriminatory, because DTE does not refuse to accept payments for capacity unless its own generating units are "new or equivalent to new."

8. <u>DTE's Proposed Transfer of RECs from the QF at no cost is Discriminatory, Violates PURPA, is not Just and Reasonable, and Inconsistent with of PA 342</u>

CAA rejects DTE's proposal to retain the RECs produced by the QF without compensating the QF for any REC value. DTE witness Padgett testified that "RECs are part of the total product value that the Company is purchasing from a QF." 2 TR 314.

CAA argues that a QF's RECs have a value therefore a QF should be compensated for that value. DTE uses QF RECs to meet its State renewable portfolio requirements. DTE witness Padgett testified: "DTE's planning includes receiving 80% of RECs from PURPA facilities in order to achieve compliance with PA295 through 2029." 2 TR 313.

Mr. Padgett further testified:

> "PURPA requires the Company to purchase energy and capacity, if needed, from QFs in part because the energy being produced is either renewable or has environmental benefits. Full service customer should realize those benefits as part of the purchase obligation going forward and should not have to pay extra for those benefits separable from the energy and capacity being purchased."
>
> 2 TR 314

CAA argues that PURPA's QF must purchase obligation does not arise because of the renewal nature of the QF's generation. If a QF produces energy from a renewable source then the QF should be compensated for any REC value. Brief p 32.

CAA rejects DTE's argument that its customers should not be required to pay for RECs because they are already paying for the environmental attributes. CAA argues that DTE's avoided cost calculations are not based on costs of a renewable resource, but are based on a fossil fuel proxy or on market costs. Id. CAA's witness Mr. Steglitz testified:

> "Staff's proposal effectively gives away public property – that is, renewable energy credits that belong to the City, for no additional benefit. If RECs are going to go to the utility under the standard offer, then there should be a real exchange of value for them and the City should see an increased avoided cost rate, an increased contract term, or some other tangible benefit to justify the loss to the City of the environmental benefit."
>
> 2 TR 263

CAA argues that the renewable energy requirements of 2008 P.A. 295, §§ 27 and 29 should be reflected in the avoided costs set for CAA's QFs. DTE's position that RECs generated by QFs should be assigned to the utility upon payment of avoided costs is a violation of FERC's requirements Brief p 33.

CAA argues that Michigan requires:

- Utilities to generate or purchase 10% of their supply from renewables currently. MCL 460.1027(3) (b);
- Renewables must be located in Michigan;
- A utility may not purchase less expensive out-of-state renewable energy. MCL 460.1029(1); and
- Utilities must meet a renewable standard of 12.5% by 2019 and 15% by 2021. PA 342, § 28.

Brief p 34

If the Commission decides RECs should be transferred to DTE upon payment of avoided costs, then under FERC's precedent, the avoided cost calculation should include the costs of other sources that will meet the REC requirements plus the cost of the fossil-fuel proxy. See, *California PUC*, 61267 Brief p 34. CAA argues that the additional costs should be based upon what DTE is paid for its own renewable generation. FERC has noted, "A state may separately provide additional compensation for environmental externalities, outside the confines of, and, in addition to the PURPA avoided cost rate, through the creation of renewable energy credits (RECs)." *California PUC*, 61,268.

CAA recommends the Commission allow QFs to retain REC's. If DTE wants to obtain the RECs to meet its renewable energy requirements, then DTE and the QF should negotiate a QF contract and set a REC value that is not included in the avoided cost rate. Brief p35

9. Staff's HPPM is Discriminatory and would Violate PURPA

CAA argues that Staff's energy component, use of MISO's LMP is not a reasonable proxy for avoided energy costs – either on a short-term basis, or using this short-term pricing over the QF's contract. 2 TR 39. Staff's proxy must include other energy costs avoided to prevent an undervaluation of the energy component to the QF. CAA witness Rabago testified:

> The cost of energy from an NGCC unit is a reasonable starting point for calculating avoided energy costs. The ICE adjustment is appropriate to reflect the fact that, but for the purchase of energy from the qualifying facility, in order to avail itself of the cost of energy from a NGCC the Company would also fact the capacity investment costs associated with a NGCC. The fixed investment cost associated with obtaining low-priced energy from an NGCC is a real cost avoided by the purchase from the qualifying facility. To ignore the ICE in setting the avoided cost would advance a fiction about the full costs of that energy that are avoided and

> would reflect improper discrimination against qualifying facilities and small power producers.
>
> 2 TR 190-191

CAA argues that Staff's use of MISO's ZRCs to determine the amount of capacity credit produced by a QF to determine avoided cost payments is inappropriate. Staff use of us the ZRC as a pricing mechanism to factor "system daily and seasonal peak period" into capacity costs results in the lowest cost option and undervalues QF capacity. CAA argues that Staff's approach does not reflect DTE's full avoided capacity costs. Brief p 38.

10. Staff's QF Contract Length and QF Standard Contract Proposals do not Comply with PURPA

CAA argues FERC's rules at 18 CFR 292.304(e) (iii) require the Commission to consider "the terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement, and sanctions for non-compliance." FERC also discussed the long-term length of contracts in its comments on PURPA in Order 69. See Order 69, 45 Fed Reg at 12,226.

CAA argues that a Commission requirement which limits a QF contract length to a short-term contract would deny a QF its right to enter into a contract or legally enforceable obligation to provide long-term commitments to DTE. As a result a QF would be prevented from receiving appropriate full avoided costs that reflect a long-term commitment in violation of PURPA. See 18 CFR 292.304(e) (3).

CAA argues that QFs need 20-year or longer contract terms in order to ensure recovery of the capital expenditures." See 2 TR 262. Staff's proposal of 5, 10, or 15-year contracts are too short and would not provide sufficient duration to obtain a return on capital investments. Staff's and DTE's proposals would be discriminatory if non-PURPA renewable energy facilities may obtain 20-year contracts while 20- year contracts are not available to PURPA QFs.

11. <u>Staff's Standard Offer Proposal does not include PURPA and FERC's Requirements nor Factors Affecting Avoided Cost Rates</u>

CAA supports Staff's proposal for a standard offer QF size cap to be in the range of 1 to 5 MW and believes it would encourage QF development. Despite CAA's support CAA argues that Staff's proposed standard offer fails to meet PURPA's and FERC rules requirements because it fails to consider a number of factors. See Brief pp 40-41.

Pursuant to Section 292.304(c) (3) (I), standard offer rates for purchases are required to be consistent with both the standards for avoided costs (rates for purchase, Section 292.304(a)), and the "factors affecting rates for purchases" in Section 292.304(e). The factors listed for the in Section 292.304(e) must be considered by the Commission "to the extent practicable." CAA argues that because neither Staff nor DTE considered the required factors, the standard offer tariff does not reflect DTE full avoided costs, and therefore is set discriminatorily low. Brief p 41.

FERC's PURPA rules state that a state "may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies" when formulating standard rates. (Section 292.304(c) (ii)). CAA argues that Staff's failure to consider and value the distinct operational values of the QFs results in an improper determination DTE's full avoided costs pursuant to Section 292.304(c) and (e). Brief p 42.

12. <u>Transfer Price Method (TPM) is the only Avoided Cost Method that is Just and Reasonable in the Public Interest and Non-Discriminatory</u>

The Transfer Price Method (TPM) was developed by the Commission based upon the requirements of Sections 45 and 49 of 2008 PA 295. The passage of 2016 PA 342 which includes Michigan's Renewable Portfolio Standard ("RPS"), affirmed Sections 45 and 49 of 2008 PA 295. Public Act 342, provides that the RPS will remain a mandate for the next five years, after which time the regulated utilities will have ongoing renewable energy and energy waste reduction "goals" to meet. CAA argues that PA 342 assures that the TPM will continue to be a reasonable and prudent method for calculating "the energy and capacity (nonrenewable market price component) through a new long term power purchase agreement for traditional fossil fuel electric generation," Brief p 44.

CAA argues that the TPM adopted by the Commission as a cost pricing methodology for renewable energy, is the only method which meets the Federal requirements for a full avoided costs. If the TPM is only used by the Commission to set non-QF renewable energy prices and is not available to determine QF avoided cost then the Commission's action would be discriminatory. CAA argues that the TPM should be the Commission's avoided cost method because:

- It is based on a NGCC unit, which is the appropriate proxy for the avoided cost for both energy and capacity,
- It is just and reasonable,
- Non-discriminatory towards the QF,
- It is in the public interest,
- Offers a projected cost over a multi-year (20) planning horizon, and
- Provides an avoided cost schedule that could be the basis of multi-year, long-term power purchase agreements. Brief p 44

13. DTE Endorses the Transfer Price Schedule to Establish Costs for its Own Projects

CAA argues that DTE, in other proceedings before the Commission, has endorsed the use of the TPM. In U-18082, DTE filed an application for a renewable energy cost reconciliation and requested "expeditious approval of and authority to use, effective as of the U-18082 Order Date the new Transfer Price Schedule submitted herewith and identified as Exhibit A-4, Schedule A1 for DTE Electric 2008 PA 295 Renewable Energy Contracts and Company-owned Renewable Energy Systems that the Commission approves." Brief p 45. In U-18082 DTE filed testimony in which it indicated that the Transfer Price Schedule filed in that proceeding was reasonable. Brief p 46.

On Pages 46-47 of CAA's brief it provides a comparison of the Transfer Price Schedule provided in U-18082 and Exhibit A-4 filed in his docket. CAA argues that the transfer prices DTE is proposing in this matter are much less (approx. 30% less) than the transfer prices it is simultaneously proposing in U-18082 for its own projects. CAA argues what DTE is proposing in this docket is discriminatory against QFs and therefore violates federal law. In U-18082 Staff witness Harlow testified:

> "Staff contends that, given current market conditions, the market will converge towards the price of a new NGCC plant every year. In an effort to assign value the non-renewable component of renewable energy generation, Staff developed this transfer price methodology so that it will result in a proxy for how a long term power purchase agreement with inflation would be structured."

Direct Testimony of Jesse J. Harlow, U-18082, and pp. 9-10. Brief p 48

CAA argues that the appropriate Transfer Price Schedule for QF projects on DTE's system is the one that will be approved in U-18082. Brief p 48.

CAA argues that the Transfer Price Schedule reflects the value of the non-renewable component of energy generation, but does not reflect any added value that is provided by Renewable Energy Credits or other environmental attributes. Those additional values should be also be considered.

14. DTE's Objections to the TPM are without Merit

CAA does not agree with DTE's witness Padgett's testimony that DTE "does not support the Transfer Price method because the capacity payments are not discounted to reflect the true value of the intermittent capacity value recognized in MISO through an ELCC adjustment." 2 TR 310. CAA argues that a QF's capacity is what it can generate, not what DTE can use in MISO. According to FERC, DTE's obligation to purchase QF capacity arises when a QF offers that capacity with firm contractual requirements Brief p 48. DTE may not discount through some market mechanism the QF's capacity as offered, and so pay the QF less.

CAA also does not agree with DTE's argument that "the energy component of the avoided cost should not be based on a "snapshot in time" price forecast given the historical volatile nature of the gas market which is then levelized over a lengthy period of time." 2 TR 311. CAA argues that a "snapshot in time" is specifically what FERC intended PURPA to allow QFs to obtain. Brief pp 49-50, CAA believes that DTE's objections to using a forecast of costs for setting avoided costs is unfounded, and to do as DTE suggests, would violate FERC's rules. Id.

15. DTE's and Staff's Avoided Cost Methodologies are not in the Public Interest, Discriminatorily Low, and in Violation of PURPA

CAA argues that the Commission's adoption of either DTE's or Staff's avoided cost methods would discourage cogeneration and small power production and provide QFs with lower payments than DTE receives for comparable facilities. CAA believes that Staff and DTE support a Transfer Price Schedule for DTE's own facilities that would pay DTE between 26% to 34% more for its generation than is being proposed under either Staff's or DTE's methods according to the values set forth in Exhibits A-1 (Revised) and A-3.

CAA argues that it would not be in the public interest to pay QFs a reduced rate in order to save DTE's consumers money. The lowest cost option would be discriminatory toward a QF and violates the goal of PURPA, FERC's rules and regulations implementing the law.

CAA argues that its QF facilities have had contracts with DTE for over thirty years, and were in operation for sixty or seventy years before that. Each of CAA QFs is considered a "base load" facility that has provided reliable energy at costs below DTE's regulated electric rates for many years. CAA argues that its QF facilities provide valuable renewable energy, recreational opportunities, and economic development. These benefits clearly meet the PURPA "public interest" standard and should be recognized in the Commission's avoided cost methodology.

Brief pp 52-53.

D. <u>ELPC</u>

Mr. Karl R. Rábago, B.B.A., J.D., L.L.M, principal of Rábago Energy LLC testified regarding the importance of PURPA's non-discriminatory provisions and provided recommendations for the Commission. Mr. Rabago's direct testimony is organized as follows:

- Introduction, 2 TR 135-137
- Background and Purpose of PURPA, 2TR 137-139

- Michigan’s Role in Implementing PURPA, 2TR 139-149
- The Importance of a Comprehensive, Non-Discriminatory Approach to Avoid Costs, 2 TR 149-150
- Full Avoided Cost Methods, 2TR 150-159
- Full Avoided Cost Methods for Distributed Solar Generation: Value of Solar Analysis, 2 TR-159-164
- Deficiencies in the Company Proposal, 2TR 164-172
- Conclusions, 2TR172-173
- Recommendations, 2TR 173- 176

Mr. Rabago did not sponsor any exhibits.

Mr. Douglas B. Jester, B.I.S., M.S., M.S. Principal of 5 Lakes Energy LLC, testified regarding his PURPA avoided cost recommendations to the Commission and deficiencies in the DTE’s proposal. Mr. Jester’s direct testimony is organized as follows:

- PURPA Background, 2TR 181-189;
- PURPA Avoided Costs, 2TR 189-212;
- DTE s Proposal Is Unduly Discriminatory Against PURPA Qualifying Facilities And Is Anti-Competitive, 2TR 212-214;
- Contract Term And Other Provisions Of A PURPA Contract, 2TR 214-216;
- Disposition Of Renewable Energy Credits In A PURPA, 2TR 216-217; and
- Contract Standard-Offer Contracts under PURPA, 2TR 217-220.

Mr. Jester also provided rebuttal testimony in which he responds to the analysis and recommendations of Staff witnesses Baldwin and Harlow. 2 TR 223- 230. Mr. Jester also responds to a recent package of bills passed by the Michigan legislature and signed into law SB-437 and SB- 438. 2 TR 223- 234.

Mr. Adam Schumaker, M.E.S. Director of Business Development, Sustainable Power Group, LLC testified regarding Solar Power Project Financing and Solar Power Purchase Agreements. 2TR 235-245. Mr. Schumaker sponsored Exhibit ELP-6 which provides information regarding the financing of solar projects and ELP-7 which provides information regarding QF solar project contracts.

Mr. Rand Duewerke, Senior Research Analysts, Sustainable Partners, LLC provided testimony regarding the financing of CHP projects. 2 TR-247-250.

ELPC argues in its brief that the Commission should adopt Staff's recommendations for calculating avoided energy and capacity costs as a "starting point" for a just and reasonable avoided cost methodology. ELPC believes that the Commission should include other quantifiable elements to Staff's avoided cost and disagrees with DTE's belief that Staff's proposed methodology will increase customer's costs.

1. <u>Staff's Proposed Avoided Capacity Cost Method</u>

ELPC agrees with Staff's proposal to use a natural gas combustion turbine as the proxy plant for capacity because ELPC agrees with that a NGCT is the best measure of DTE's incremental cost avoided by entering into long-term QF contracts. Therefore, ELPC believes that Staff's capacity cost proposal is just and reasonable. ELPC witness Jester's testimony is consistent with Staff witness Harlow's testimony 2 TR 103 that NGCTs are the resource most commonly used to provide the reserve margin a utility needs to meet MISO capacity requirements. *See* 2 TR 196.

ELPC also agrees with Staff's proposed adjustment to capacity values based on the Effective Load Carrying Cost (ELCC) of the QF and the proxy plant.

ELPC disagrees with DTE's proposal to use MISO's Planning Resource Auction (PRA) to determine DTE's avoided capacity costs. See 2 TR 327. ELPC agrees with Staff witness Harlow that the MISO PRA does not account for the value of long-term capacity and is therefore discriminatory to QFs. *See* 2 TR 102.

2. <u>DTE's Proposal to Limit Capacity Payments Based on its Five-Year Forecast</u>

ELPC agrees with Staff witness Harlow's position (See 2 TR 99) that DTE's avoided cost should be based on capacity needs over a long-term planning period to avoid discrimination against QFs and to maximize customer benefit from purchases from QFs. ELPC believes that DTE's proposal to link capacity payments to a five-year planning horizon would undervalue DTE's avoided cost of deferring capacity additions because DTE is looking beyond five years when deciding whether to build a large generation plant.

ELPC argues because DTE uses at least a ten-year forecast in its own capacity planning and it has identified capacity shortfalls in that same ten-year forecast it would discriminate against QFs if a shorter period is used to determine DTE's PURPA must purchase capacity. Brief p 10 .In support ELPC argues that DTE initially provided a five-year forecast of capacity which showed no DTE capacity needs. 2 TR 298. DTE in response to a discovery request, provided a ten-year forecast which shows DTE has capacity shortfall of 503 megawatts in forecast year 6 and a 265 MW to 1304 MW shortfall in years 7 through 10. See 2 TR 57. ELPC argues that using a short-term capacity-planning horizon will "unfairly discriminate against qualifying facilities by using time horizons and valuations that the utility does not assign to its self-build options." 2 TR 154. Brief p 11.

3. Staff's Proposed Avoided Energy Costs

ELPC agrees with Staff's proposal to use the forecasted variable costs of a NGCC plant with an adjustment for the fixed investment cost attributable to energy. ELPC believes that Staff's proposal best reflects DTE's avoided energy costs. Brief p 11. ELPC also agrees with Staff's proposal to allow QFs three options to choose from for DTE's avoided cost of energy so long as the Commission's approved avoid cost method retains the three option approach and the QF's ability to select an option. ELPC believes that Staff's three option approach complies with PURPA as long as the Commission retains all three alternatives with selection made by QF. *See* 18 C.F.R. § 292.304(d) (requiring rates for purchase "at the option of the qualifying facility" to be based either on avoided costs calculated at the time of delivery or avoided costs calculated at the time the obligation is incurred). *Id* In addition, ELPC argues that Staff's proposal to provide QFs with three options for avoided cost of energy complies with PURPA only if the NGCC plus ICE option is retained as one of the QFs options.

4. Renewable Energy

ELPC argues that the Commission should set avoided cost at no less than the DTE's cost to meet all applicable renewable energy or other generation requirements for particular technologies**.** ELPC witnesses Jester and Rabago testified that Staff's proxy plant approach should be modified to meet Michigan's renewable energy requirements. 2 TR 190, 2 TR 145. ELPC believes the avoided cost should be the larger of DTE's actual cost of generation from that renewable energy technology when owned by DTE or Staff's recommend proxy plant method .*See* 2 TR 190. ELPC believes that doing so would be consistent with FERC rulings that the Commission may take into account "obligations imposed by the state" that require utilities to "purchase energy from particular sources of energy" such as through a renewable energy standard or other state policy. *California Public Utilities Commission*, 133 F.E.R.C. P61, 059, ¶ 26 (2010). Brief p 14.

ELPC believes the Commission's avoided cost method should consider the following DTE's renewable obligations created by 2016 PA 341 and 2016 PA 342:

- Increase in Michigan's renewable portfolio standard ("RPS") from 10 percent to 15 percent by 2021;
- An interim standard of 12.5 percent by 2019;
- A goal of 35 percent from renewable sources and energy efficiency by 2025;and
- The requirement DTE provide renewable energy options to customers. *See* MICH. COMP. LAWS § 460.1028(1) (c), § 460.1001(3) (effective April 20, 2017).

Brief p 15

If DTE purchases power from a renewable QF, to comply with mandated standards or to respond with DTE customer demand, the Commission should set DTE's avoided cost at the larger of the requirement-specific cost to DTE of providing renewable energy or Staff's proxy plan. According to ELPC it generally costs DTE more to provide energy to its customers from renewable resources than from other generating resources. See 2 TR 346. Brief p 15.

ELPC recommends the Commission require DTE to provide its projected cost to comply with state renewable energy requirements and its customers' demand for renewable energy products at the biennial PURPA reviews.

5. <u>Technology Specific Cost should be included in DTE's Avoided Costs</u>

ELPC argues the Commission should establish a process to quantify technology-specific avoided cost factors such as transportation, distribution, delivery, and system costs. ELPC believes that these are the real distributed generation costs that are or can be avoided. *See* 2 TR 155. Brief p 16.

Distributed generation and renewable generation hedges resource diversification, risk reduction, resilience, and complying with environmental regulation avoided costs. ELPC argues that FERC regulations provide an avoided cost method to the extent practicable must take into account these factors when determining the full and fair QF avoided cost. 18 C.F.R. 292.304(e). In addition, FERC regulations provide these rates "may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies." § 292.304(c) (3) (ii). Brief p 16.

ELPC witness Rábago testified that this "differentiation among technologies by characteristics that reveal differences in the incremental costs avoided by those technologies is integral to the non-discrimination requirement." 2 TR 157.

ELPC witness Rabago points out the Commission's Solar Working Group is assessing and quantifying the various energy, capacity, line loss savings, financial, and security benefits of distributed solar. *See e.g.*, SOLAR WORKING GROUP, STAFF REPORT, Case U-17302 at Dkt. #106 (July 1, 2014). ELPC witness Rábago recommends the Commission direct Staff to develop a full and fair avoided cost rate for distributed solar. 2 TR 157-58. ELPC witness Rábago recommends the Commission consider the values and methods described in "PV Valuation Methodology: Recommendations for Regulated Utilities in Michigan," authored by Clean Power Research ("CPR") to "gather and refine the necessary information for use in improved methodologies in future biennial reviews." 2 TR 162, *citing* Ex. ELP-4.

ELPC recommends the Commission should direct Staff to:

- continue to develop a full and complete solar valuation study;
- require DTE to participate in this process and provide all information necessary to complete the analysis; and
- Incorporate the results into the Commission's next biennial adjustment of avoided costs.

Brief p 17-18

6. Standard Offer Tariff

ELPC believes the Commission should extend standard offer rates to projects up to 20 MW. FERC regulations give the Commission discretion to establish large QF standard rates because standard rates reduce transaction costs and encourage cogeneration and small power production. 45 Fed. Reg. 12214, at 12223. ELPC argues that its position is consistent with Staff witness Baldwin's testimony that the purpose of the standard offer is to "reduce" the "contracting and transaction costs for both the utility and the QF." 2 TR 74, Brief p 29. ELPC witness Schumaker testified that limiting the standard offer capacity to 20 MW will mitigate the transaction costs that often "make solar projects more difficult to finance for all QFs up to 20 MW." 2 TR 243.

ELPC believes the expanded availability of a standard rate through a higher cap:

- Reduces transaction costs for QF project;
- Avoids the cost and burden of establishing an individualized avoided cost rate;
- Reduces barriers to entry;
- Furthers PURPA's goals (development of renewable energy and reduce reliance on fossil fuels); and

- Benefits the public interest.

Brief p 19

ELPC witness Jester testified that the negotiation of a QF contract can cost $25,000 or more, and for smaller projects that cost may cause a significant percentage reduction in avoided capacity payments. 2 TR 218. Staff witness Baldwin testified that if the avoided cost is appropriately set “customers will not be negatively impacted when the contracting and transaction costs for both the utility and the QF are reduced through the use of the Standard Offer tariff.” 2 TR 74. Brief p 19.

ELPC argues that a standard offer for all projects that face discriminatory access to wholesale markets would promote growth of QFs “where private capital is expended without unreasonable risk” (2 TR 127) and greater private capital investment furthers PURPA’s effort to increase “the utilization of cogeneration and small power production facilities.” *Am. Paper Inst*., 461 U.S. at 417. Brief p 19.

ELPC disagrees with DTE‘s proposed 100kW standard offer cap. ELPC believes that DTE has provided no explanation why the standard offer should be capped at 100 kW. DTE witness Padgett testified “DTE Electric historically has not realized any formal opposition or criticism concerning the 100 kW cap.” 2 TR 303. ELPC argues DTE has not experienced any opposition because according to DTE witness Padgett’s testimony DTE has not entered into a QF contract in 10 years. See 2 TR 343.

DTE’s only argument in support of this position against a 20 MW cap is that “[i]ssues related to dispatch ability, interconnection needs, performance requirements, and technology differences” caution against raising the cap. See 2 TR 336. ELPC argues that DTE has provided no explanation:

- What the issues entail;

- How different QF sizes would affect DTE; or
- Why these issues support capping the standard offer at 100 kW.

Brief p 21

ELPC believes that DTE's standard offer 100kW cap is motivated by an anti-competitive desire to limit QF development, which is contrary to PURPA's intent to encourage QF development.

ELPC argues that if the Commission has concerns whether a 20 MW cap would increase the development of QF the Commission may adjust the avoided capacity cost during the biennial review process. Brief p. 21. ELPC witness Jester testified that neither a "forty-fold increase in the pace of development of new" QFs up to 20MW nor a "sixty-fold increase in the pace of development of new" QFs up to 20MW would saturate capacity requirements in DTE's service territory by 2020. 2 TR 224. Brief p 21.

7. <u>QF Contracts</u>

ELPC believes the Commission should set contract terms of no less than 15 years to prevent discrimination against QFs. ELPC argues that an adequate contract term length:

- Prevents discrimination against QFs;
- Furthers PURPA's goals;
- Allows QFs to recover costs;
- Increases the utilization of cogeneration and small power production facilities; and
- Reduces reliance on fossil fuels.

Brief p 22

ELPC witness Schumaker testified that a short standard offer term “prejudices QF projects when competing at avoided cost rates which are based on” non-QF projects “that are amortized over 20 years or longer.” 2 TR 243.

ELPC witness Jester recommends a standard offer contract term which reflects DTE’s avoided financing costs that would “be sufficient for at least repayment of debt and reasonable return on equity within the initial contract term,” as is allowed under DTE’s capacity financing. 2 TR 215. ELPC witness Schumaker testified that 15 years is the shortest “term required to make a solar project financeable.” 2 TR 238. Mr. Schumaker testified that debt providers finance QF projects for the length of a Power Purchase Agreement (PPA) or less. More debt can be secured by a contract with a longer the standard offer term. 2 TR 239. With more debt secured, the ability to finance the QF project is not hindered. 2 TR 241. Brief p 22.

ELPC rejects DTE’s position that all QF contract terms be negotiated with DTE. See2 TR 312. ELPC believes that DTE’s position would:

- Increase transaction costs;
- Unnecessarily hinder QF development; and
- Prejudice against QFs through inadequate contract terms.

Brief p. 23

ELPC agrees with Staff witness Baldwin’s testimony that limiting QF contract terms to no more than five years (as DTE recommends) “would be a departure from many of the previous PURPA contracts” and a departure from traditional utility cost recovery, which “is based on recovering costs over the expected life of the project.” See 2 TR 77.

ELPC points out that Ms. Baldwin further testified that she “is not aware of any generation projects (anaerobic digester, solar, wind, and landfill gas, hydro) with a life of several years or less.” *Id.*

ELPC recommends that the QF standard offer contact should be 15 years or more to "ensure fairness to QFs” and promote PURPA’s goals of increasing “small power production facilities” and reducing “reliance on fossil fuels” at no more than the utility’s avoided cost. *Am. Paper Inst.,* 461 U.S. at 417. Brief p23. ELPC argues that DTE’s proposal to negotiate all contract terms is discriminatory, would unnecessarily increase costs, and would violate PURPA. Id.

8. Standard Offer Availability

ELPC argues that DTE’s standard offer should be made available to all QFs, not just DTE’s full-service customers. DTE witness Padgett testified that only QFs who are DTE full-service customers should be allowed to utilize the standard offer. *See* 2 TR 338. ELPC argues that DTE’s position conflicts with PURPA and should be rejected. PURPA regulations require DTE to purchase energy and capacity made available from QFs. *See* 18 CFR § 292.303(a). ELPC argues there are no FERC regulations or orders which limit DTE’s must purchase obligation to full-service customers. Exemptions are found at 18 CFR § 292.309 but that regulation does include a requirement that a QF be a full-service customer. Brief p 23-24.

E. GLREA

GLRE believes that DTE’s and Staff’s proposed avoided cost methodologies and DTE’s proposed standard rate tariff do not accomplish the purposes and objectives of PURPA and the goals and requirements of Michigan’s new Acts 341 and 342. GLREA believes that Staff's proposals and suggestions regarding DTE's avoided cost proposal and Standard Contract have some shortcomings. Brief p 2.

GLREA witness Geoffrey C. Crandall, B.S., Principal and the Vice President of MSB Energy Associates, Inc., 2 TR 111-114, summarizes and discusses why GLREA believes that DTE's and Staff's proposed avoided cost methods are unreasonable and inconsistent with PURPA.

Mr. Crandall testified that the avoid cost methods proposed by Staff are in general, the methods which have been used for decades throughout the United States to calculate avoided costs. Staff's method does not include DTE's full avoided costs because, according to Mr. Crandall, Staff's method does not include the following:

- Avoided transmission and distribution costs,
- Quantifiable environmental costs (e.g., purchasing RECs),
- Line losses, and
- Reserve margin requirements (where the alternative resource, by reducing load supplied by the utility, reduces the utility's capacity requirement by the load plus the reserve margin).

2 TR 113

Mr. Crandall testified that Staff's options for calculating avoided capacity and energy costs within the hybrid proxy plant method are generally valid but all avoided costs must be included and properly reflected in each specific combination and purpose served by the avoided cost calculation. 2 TR 113. Staff's avoided capacity cost Option 2 allows the capacity cost to be set at zero if DTE has no capacity need during the forecast period. If the alternative resource has a life that is shorter than the planning horizon, e.g., a DSM measure with a 5-year life in a 10-year forecast period during which no capacity is needed then this approach would be reasonable. If the DSM resource has a 15-year life, or a small power production or cogeneration facility (SPPCF) e.g. QF resource a 30-year life, it will provide a capacity avoidance benefit after the 10-year forecasting period. Mr. Crandall testified that benefit should be reflected in resource planning and acquisition decisions and the avoided capacity value should be reflected by discounting the number of years until capacity is needed. DTE's proposal to utilize a 5-year planning horizon undervalues future avoided capacity costs. 2TR 113. Brief p 3.

Mr. Crandall testified that Staff's Option 3, which bases avoided energy cost on the production cost of a natural gas-fired combined cycle unit, is wrong because it understates the avoided energy cost. Staff's Options 1 and 2 (avoided energy), are based on LMPs (market-clearing prices that reflect the instantaneous bid prices of existing resources). LMPs are neither long term clearing prices nor production costs for new market entrants. 2 TR 133-114. Brief p 4.

Mr. Crandall testified that Staff's Option 3 assumes that the avoided plant operates in isolation from the utility system. The addition of a generating resource, whether utility-owned or power purchased from a SPPCF, shifts the marginal energy cost on the system. The avoided energy cost in a utility system involving multiple generation resources is the marginal system production cost, not the energy cost of the added or avoided plant. 2 TR 114. MISO uses this same approach to set the clearing price and LMPs; DTE pays the clearing price for energy. The infra-marginal plants, although being lower cost, do not set the price of energy. GLREA believes that DTE's approach undervalues the avoided energy cost and would underpay the SPPCF for energy supplied *.Id*.

1. <u>Comparative IRP Avoided Costs</u>

GRLEA recommends the Commission adopt an avoided cost method based on comparative IRP analysis. Mr. Crandall testified that the comparative IRP method compares a long-range expansion plan without SPPCFs to a long-range expansion plan with SPPCFs. Brief p 5. The difference between the two is the avoided cost resulting from the SPPCFs. According to Mr. Crandall the IRP method:

- Provides a detailed and comprehensive analysis;
- Does not rely on the proxy plant or other approximations;
- Is more complicated than proxy methods;
- Requires long-term projections of load, fuel costs, resource expansion plans; and
- Uses the same inputs and methods used by DTE in its long term planning.

2 TR 115

Because the SPPCFs are likely to be small, GLREA believes the Commission should consider a block of SPPCFs rather than individual projects. The costs (payments) would be made on a per unit basis (e.g., X $/KW and Y $/MWH for any SPPCF projects within that block. Id.

GLERA believes that DTE's proposed tariffs are unreasonable because the tariffs understate the value of DTE's avoided cost, create barriers (see Exhibit A-6) creates DTE's Standard Offer applies to small SPPCFs with a design capacity of 100 kW or less. According to Mr. Crandall testimony DTE's proposed Standard Offer tariff presents the following problems:

- The term of the Standard Offer contract proposed to be subject to negotiation would limit the period to shorter than the life of the SPPCF. If payments for SPPCF generation are not known for the life of the

SPPCF, the uncertainty would represent a barrier to obtaining financing to build the SPPCF project.

- The Standard Offer tariff applies only to SPPCFs with a capacity under 100KW. The Tariff should apply to SPPCF's up to 20 MW.

GLREA believes that the standard offer tariffs cap should be 20 MW and does not agree with Staff's TAC report 5 MW Standard offer Tariff cap. Brief p 6.

2. <u>DTE's Proposed Avoided Energy Cost Method</u>

GLREA rejects DTE's method for calculating avoided energy costs based on utilization of a NGCC proxy plan variable cost, i.e., fuel commodity and delivery cost times heat rate plus the variable operating cost. Brief p 7. Mr. Crandall testified that DTE's proposed method is flawed for following reasons:

- LMP's are an energy market clearing price which do not to reflect much, if any, capacity value (except in times of imminent scarcity and then only in a the short term).

- MISO recognizes that there are capacity values above the LMP which is why MISO holds Planning Resource Auctions (PRA's). DTE has not included capacity values from PRAs in its preferred avoided cost methodology or the proposed energy only tariff when DTE has sufficient capacity.

- DTE pays more for SPPCF power when it does not need capacity than when DTE needs capacity. This represents a fundamental flaw in the avoided cost methodology proposed by DTE.

2 TR 116-117

3. <u>DTE's Tariffs</u>

GLREA disagrees with DTE's proposed tariff language which provides that DTE will pay a QF for capacity and energy, using DTE's avoided cost method, when DTE needs capacity. When DTE does not need capacity DTE proposed to pay a QF the LMP for energy and nothing for capacity. See Exhibit A-6. Brief p 7.

DTE's proposed tariff paragraph B.1.b for new facilities provides: "if capacity is needed, the rate will be based on the avoided capacity and energy costs in the Company's biennial avoided cost filing with the Commission." If DTE determines that it needs capacity, then existing SPPCFs will be paid at the avoided energy costs as filed each biennium, calculated using DTE's preferred approach based on the NGCC proxy plant, unless the SPPCF can prove that the existing SPPCF facility is new or equivalent to new. 2 TR 117.

GLREA's witness Mr. Crandall testified DTE's tariff terms are unreasonable, logically inconsistent, flawed and incorrectly assume that when capacity is needed the SPPCF is more valuable than when capacity is not needed. 2 TR 118-119. Brief p 8

DTE witness Mikulan shows the avoided costs estimated using DTE's preferred method See Exhibit A-1 and A-2.The avoided energy cost is 2.04 cents per kWh. The avoided capacity costs range from 0.78 cents per kWh to 3.78 cents per kWh, depending on the type of SPPCF technology. By comparison, the average LMP at the DECO.NEC load zone for 2014 is 4.156 cents/kWh. 2TR 119 Brief p 8.

Mr. Crandall testified that the information provided by DTE shows that the rates DTE proposes:

- Would pay to SPPCFs would be higher when DTE did not need capacity than when it did.
- Payments to existing SPPCFs would decrease dramatically (to one-half) when DTE determines capacity is needed.
- New biomass, landfill gas and wind SPPCFs would be lower when capacity is needed than when not.
- Hydro and solar SPPCFs may get paid more when capacity is needed than when not.

2TR 120, Brief p 8-9

Mr. Crandall testified that DTE's proposal is illogical and inconsistent and illustrates how DTE's proposed avoided energy costs methods and calculations understate the true value of SPPCF capacity and energy. He provide two examples:

- Avoided capacity value is zero when DTE does not need capacity.
- Pay avoided energy at the incremental production cost of the avoided Generating plant rather than the actual LMP.

Id.

GLREA believes that SPPCF capacity has value even when DTE has no need for new capacity for the following reasons:

- An SPPCF with a life longer than DTE proposed would have value because it would provide capacity beyond the contract period;
- DTE's proposal to not pay for capacity when DTE has sufficient capacity deprives MISO of the SPPCF capacity and the SPPCF of revenues.

GLREA argues that If DTE is allowed to avoid making payments to the SPPCF then those actions would:

- Reduce SPPCF revenue;
- Make it more difficult for the SPPCF to obtain financing;
- Create barriers to the SPPCF project construction; and
- Be inconsistent with PURPA's intent to levelized payments, stabilize and advance revenue, and increase project financially viability.

Mr. Crandall testified that If DTE can sell its excess capacity short term through the PRA then DTE and customers will benefit from the SPPCF capacity. If the SPPCF is on DTE's system, then DTE has an additional increment of capacity available to sell. If DTE buys SPPCF power at the PRA clearing price and sells excess capacity at the PRA clearing price, DTE's ratepayers are not harmed. 2 TR 121-122.

GLREA disagrees with DTE's conclusion that capacity and energy costs for an avoided plant must be based on the natural gas combined cycle proxy plant and that it is inappropriate to develop avoided costs that combine MISO pricing with unrelated capacity costs (LKM-4, lines 18-21). DTE's avoided cost method approach focuses on the capacity and energy costs of a proxy (NGCC) for an avoided plant and understates avoided costs. 2 TR 122. GLREA argues the comparative IRP analyses method is a more sophisticated analyses used to calculate the production cost with and without the SPPCF or DSM resource. Brief p 10.

Mr Crandall testified that the LMP approach approximates the system impact of a SPPCF addition but does not disclose the change in LMP as a result of the SPPCF. A small SPPCF on a large system (MISO) would not change the LMP much and the value of the avoided energy is effectively the LMP times the kWh avoided. DTE's avoided proxy new plant is likely to be more efficient and cheaper to operate than the marginal plant. Because the marginal plant sets the LMPs, valuing the avoided energy cost equal to the production cost of the avoided plant, LMPs are likely to be higher than the avoided plant energy cost. 2 TR 123.

Mr. Crandall testified that the market values energy at the clearing price – the LMP. DTE proposal to pay the SPPCF the avoided plant energy cost undervalues SPPCF for the value of the energy it provides because DTE's avoided energy costs would likely be less than the market value of the energy. Id.

4. <u>DTE's Proposed Avoided Cost</u>

DTE witness Mikulan's testimony shows DTE's revised calculation of projected avoided energy cost is 2.04 cents/kWh. The average LMP at the DECO.NEC load zone for 2014 is 4.156 cents/kWh. DTE's calculation of avoided energy cost is less than one-half of the actual cost DTE paid to MISO for energy. 2 TR 123-124.

Mr. Crandall testified that if DTE paid the SPPCF the LMP rather than the incremental production cost of the avoided plant DTE customers would not be harmed but it would eliminate a DTE profit center. Resources with lower production costs are able to generate revenues to offset the fuel and purchased power costs (if a utility) or up front generating plant costs (if a non-regulated supplier). DTE purchases its power from MISO at the LMP prices. DTE is simultaneously buying power at the LMP price, and if selected for dispatch, selling power to MISO at LMP prices and making a margin on the sales based on the difference between the LMP and the production costs. 2 TR 1124. Brief p 11.

Mr. Crandall testified that when DTE buys power from the SPPCF at the proxy plant production cost DTE has more of its native capacity to sell at the LMP. DTE is able to generate and sell more power, while making the actual margin on its plants that were dispatched by MISO. When DTE buys SPPCF power at the LMP price the purchase reduces the need to purchase from MISO by an equal amount. If DTE's MISO purchase and SPPCF purchase are done at LMP DTE is indifferent and the SPPCF gets the full value of energy. If DTE buys from the SPPCF at a lower price DTE makes money, but the SPPCF gets less than actual value of the energy it provides. 2 TR 124-125. Brief p 11.

5. <u>DTE's Proposal does not Reflect the Full Avoided Cost for SPPCF Projects</u>

GLREA argues that if DTE's proposal is the full value of its avoided costs DTE should be indifferent and willing to cap their cost recovery for DTE plants to the terms they are offering to the SPPCF sellers. DTE should be willing to accept the same requirements and limitations on itself. Under a comparability test DTE should be willing to accept:

- Capital cost recovery through a series of renegotiable maximum five year periods. At the end of each five-year period, the Commission could authorize new rates with no assurance of continuity.

- Non recovery of capital costs if capacity is not needed because DTE has enough capacity to meet peak load plus reserve margin.

- Limited cost recovery for variable costs to the production costs of the proxy plant (NGCC).

2 TR 125-126, Brief pp 11-12

6. <u>GLREA Recommends a 20 MW Standard Tariff Cap</u>

GLREA witness Crandall recommends a 20 MW standard tariff cap for SPPCF projects up to 20 MWs, at the discretion of the SPPCF, should be eligible to participate under either the standard offer tariff or to negotiate their own contract terms. GLREA does not support Staff's 5 MW standard tariff cap.

Mr. Crandall testified that GLREA believes the standard rate tariff should be available to customers between 1kW and 20 MW for the following reasons:

1) DTE's proposed the standard rate offer 100 kW cap (See Exhibit A-6) is far less than Staff's 5 MW TAC Report proposal.

2) A 20 MW cap would increase SPPCF access to private capital with reduced risk and decrease DTE's need to borrow funds.

3) A 20 MW cap would diversify electric generation ,strengthen the grid , diversify the source of electric generation and enhance energy security by reducing reliance on large central generating units which are vulnerable to terrorist attacks, disruptions, outages due to fires, storms, plant malfunctions, or other factors.

4) The Staff's PURPA TAC reached no consensus or compelling reasons to limit the standard tariff size.

5) DTE's recommend SPPCF capacity limitation is inconsistent with DTE's plans to add plant capacity in large increment with gas plants having far larger capacity than a 20 MW (or less) SPPCF facility.

2 TR 126-127, Brief p 13

7. <u>Recommended Contract Length for SPPCFs</u>

DTE witness Padgett indicated that "DTE believes that arbitrarily setting contract length as part of this methodology review is not in the interest of either party and should be left to the negotiation process." GLREA's witness Mr. Crandall recommends a SPPCF contract length of a minimum of 17.5 years (at the discretion of the SPPCF). Mr. Crandall testified that this recommendation is consistent with Section 6j (13) (b) of Act 304, which provides in pertinent part:

> The financing period for a qualifying facility during which previously approved capacity charges shall not be subject to commission reconsideration shall be 17.5 years, beginning with the date of commercial operation, for all qualifying facilities, except that the minimum financing period before reconsideration of the previously approved capacity charges shall be for the duration of the financing for a qualifying facility which produces electric energy by the use of biomass, waste, wood, hydroelectric, wind, and other renewable resources, or any combination of renewable resources, as the primary energy source.

Avoided costs should be set at a level that is:

- Just and reasonable;
- Fair and nondiscriminatory;
- At a level which promotes the development of SPPCFs; and
- Consistent with PURPA and FERC regulations and interpretations.

Mr. Crandall testified that a longer contract term such as a minimum of 17.5 years (at the discretion of the SPPCF) would be reasonable and in the public interest. A longer contract term would:

- Enable an accurate comparison between SPPCF projects and DTE's building or purchasing a new power plant or purchasing power;
- Facilitate the securing of financing of new or existing SPPCFs; and
- Ensure viability through government approval.

2 TR 128-129, Brief pp 13-14

8. DTE is not Entitled to Renewable Energy Credits

DTE witness Padgett testified that DTE is entitled to 80% of the value of the REC's from SPPCF's in operation when Act 295 became effective and 100% of the value of REC's from a new SPPCF. Mr. Padgett testified "REC's are part of the total product value that the company is purchasing from a QF". GLREA does not believe that DTE is entitled to the value of the REC simply because DTE and its customers are receiving SPPCF generated power.

Mr. Crandall testified that REC'S were neither contemplated nor existed when PURPA was enacted in1978. REC's create a new stream of value that is separate and apart from avoided energy and capacity. GLREA does not agree that REC's are an integral part of energy and capacity resources acquired by DTE's.

2 TR 129, Brief p 14-15

F. Landfill Energy Systems

Landfill Energy Systems (LES) agrees with Staff that Staff's recommendations in this matter do not apply to LES's existing contract with DTE. LES agrees with Staff's testimony that the rates approved in this case would impact future Power Purchase Agreements (PPA) and would not apply to existing PPAs. LES also agrees with Staff's conclusion that federal law prohibits the Commission from altering the avoided cost rates paid in LEF's existing PPAs. Brief p. 2.

Staff witness Harlow testified that:

> "Once existing contracts expire, the QFs with pre-existing contracts, as of the filing of testimony should be compensated at the capacity rate under Staff's proposed methodology regardless of Company capacity need as these QFs already have been included in the Company's portfolio. Additionally Staff is not proposing that executed contracts be renegotiated or that their terms be altered".
>
> 2 TR 100

LEF argues that Staff's recommendation that the outcome in this matter does not apply to existing QF contracts is consistent with Federal law (See, e.g. Freehold Cogeneration Associates LP v Board of Regulatory Commissioner of New Jersey, 44 F.3d 1178,1194, 3rd Cir. 1995 cert den. 516 U.S. 815,116S.Ct. 68 (1995) ("Once the [State Commission] approved the power purchase agreement between [a QF] and [a utility] on the ground that the rates are consistent with avoided cost, any action or order by the [State Commissions] to reconsider its approval or to deny the passage of these rates to [the utility's customers under purported state authority was preempted by federal law."])

LEF requests that the Commission provide in its final order that the avoided cost methodologies approved in this case apply only to new QF contracts and do not apply to existing PPAs. Brief p.2-3.

IV.
DISCUSSION

A. Avoided Costs

PURPA "Qualifying Facilities" (QFs) are defined as qualifying cogeneration facilities or qualifying small power production facilities that have a right to be served by, and sell to the electric utility of their choosing, at a cost that does not exceed "the incremental cost to the electric utility of alternative electric energy." PURPA § 210(b); 16 USC § 824a-3(b).

The PURPA "must purchase" obligation applies to all energy and capacity made available for sale from a QF and applies to all electric utilities, unless FERC grants a waiver. 18 CFR § 292.303(a); 18 CFR § 292.309.

FERC regulations require a utility to purchase electricity from QF's at rates equal to the utility's full avoided cost. 18 CFR § 292.304. PURPA defines the "incremental cost of alternative electric energy" as:

> "[t]he cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." PURPA § 210(d); 16 USC § 824a-3(d).

FERC regulations define "avoided costs" as the:

> "Incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 CFR § 292.101(b) (6).

PURPA requires that power purchase agreements with QFs be "just and reasonable to the electric consumers of the electric utility and in the public interest." 16 USC 824a-3(b).

On May 3, 2016 in U-18091 the Commission directed DTE to file its proposed avoided cost methodologies and costs in this docket by June 17, 2016. The Commission specifically directed DTE to provide separate avoided cost calculations using the following methods and a recommended standard offer tariff:

(1) Hybrid proxy plant method developed by Staff in their April 8, 2016 Final TAC report (in U-17973);

(2) Transfer Price method developed under 2008 PA 295;

(3) Another method, if any, that DTE wished to propose; and

(4) Proposed standard offer tariff including applicable design capacity.

On June 17, 2016 DTE complied with the Commission's order by filing a report containing the requested PURPA Avoided Cost Methodologies along with a standard offer rate tariff.

DTE's witness Mikulan's testimony provides DTE's proposed avoided cost methodology calculations for new and future renewals of PURPA contracts and DTE's 5 year capacity projections. Ms. Mikulan sponsored the following exhibits:

- Revised A-1 DTE Electric's Preferred Method: "Combined Cycle Gas Turbine" (CCGT) Avoided Cost;
- A-2(Corrected) Calculation of the CCGT Capacity Component;
- A-3 Staff Method: Hybrid Proxy Plant Method;
- A-4 Transfer Price Method developed under 2008 PA 295;
- A-5 DTE Capacity Resource Plan.

See 2 TR 27-65

B. <u>DTE's Avoided Cost Method</u>

DTE's avoided cost method is based on calculations using a combined cycle proxy plant. DTE believes that its method is the only method that properly calculates DTE's avoided costs. DTE's energy component is determined by the gas price and combined cycle heat rate plus an adder for variable O&M (VOM) which is escalated separately. DTE's Exhibit Revised A-1 shows how avoided costs would be calculated using a forecasted gas price. The actual gas price at the time of PURPA QF energy generation at a DTE "avoided plant" site would be used to pay the energy component. DTE proposes to adjust the avoided capacity cost of the combined cycle based on the true value of the intermittent capacity value recognized by the Midcontinent Independent System Operator

(MISO) through an Effective Load Carrying Capability (ELCC) adjustment and the performance of the generator.

DTE's avoided capacity cost method is based on a Natural Gas Combined Cycle (NGCC) power plant which includes its capacity, O&M and energy costs. DTE argues that when DTE does not need capacity, its avoided energy cost would be the MISO locational marginal price (LMP). DTE believes that if it does not need capacity to serve its full service retail customers then DTE should only be required to purchase energy from a QF at DTEs incremental cost of energy. DTE witness Padgett testified that DTE's avoided energy cost during periods when capacity is not needed is the wholesale electric market spot price for energy or LMP in the MISO wholesale energy market. 2TR 312.

DTE indicated that, as it has done in its existing PURPA contracts, DTE would consider PURPA required factors in any QF power purchase agreement. See I Brief pp. 10-18; 2T 308; 18 CFR 292.304.

DTE witnesses Padgett and Mikulan testified that a Natural Gas Combined Cycle plant is the type of generating resource DTE would build to meet future capacity needs. 2 TR 311. DTE argues that if DTE purchases capacity from a QF during its planning period a Natural Gas Combined Cycle plant capacity would be its "incremental" and "avoided" costs. Brief pp 12-14. DTE indicated that its actual capacity payments will be based on:

- The actual QF project characteristics;
- DTE's avoided cost at the time; and
- Capacity payments would only apply when DTE requires capacity.

See 2TR 39; 307, 32, Exhibit A-2 Corrected

DTE witness Padgett's testimony provides a detailed discussion of DTE's proposed avoided cost method for capacity and energy. DTE witness Mikulan's testimony provides a break out of DTE's avoided cost capacity component. 2 TR 38-39. DTE's Exhibit A-5, is its Capacity Resource Plan for 2017-2021 and shows DTE has no need for capacity in the next 5 years.

DTE witness Mikulan provided the following avoided cost data using DTE's preferred method (as shown in the table below by type of technology) based on 2016 energy cost values:

Type of Technology	**Capacity Cost**	**Energy Cost**	**Capacity + Energy Cost**
	¢/kWH	¢/kWH	¢/kWH
Hydro	2.70¢	2.04¢	4.74¢
Biomass	2.04¢	2.04¢	4.08¢
Landfill Gas	1.81¢	2.04¢	3.85¢
Solar	3.78¢	2.04¢	5.82¢
Wind	0.78¢	2.04¢	2.82¢

The values in the above table are based on a CCGT with a 30 year life. The actual capacity payments will be based the actual QF project characteristics as explained by Mr. Padgett.

C. <u>Staff's Hybrid Proxy Avoided Cost Method</u>

Staff's recommended Hybrid Proxy avoided cost method (HPPM) uses a proxy unit for capacity and a market based pricing method for energy. Staff's method includes a fixed investment cost attributable to energy (ICE) which represents the market energy cost that is attributable when the capacity proxy is based on a natural gas combined cycle plant. Staff believes that its method provides an accurate valuation of DTE's avoided cost because it utilizes a market based approach and a proxy plant method for capacity that does not rely on the MISO capacity auctions. Staff believes that the MISO capacity auctions do not accurately value capacity and do not send appropriate market signals.

Staff's avoided cost method considers the daily and seasonal peak periods using MISO's effective load carrying capability (ELCC) to determine the amount of capacity credit provided by the QF. To the extent it is delivered to the local node the generation can be converted to zonal resource credits. Staff witness Harlow testified that, due to the intermittent nature of wind and solar, MISO has credited wind with approximately a 15% capacity credit and solar with about a 50% capacity credit. Solar generally has a lower capacity factor than wind, but has a higher ELCC because its production aligns with summer peak loads. Dispatchability of QF energy is not a factor because Staff's preferred method compensates a QF for delivered energy. According to Staff's method a QF would only be paid for energy produced by a QF and delivered to DTE. Staff recommends that QFs select one of three options for the energy component:

- The LMP at the time of delivery;
- DTE forecasts the LMP over the contract period and pays for energy on an hourly or monthly average basis according to the forecast; or
- DTE pays an energy price based on the forecasted variable cost of a NGCC.

See Exhibit S-5 (JJH- 3).

D. Intervenors Recommended Avoided Cost Methods

1. ELPC

ELPC agrees with Staff's proposal to use a natural gas combustion turbine as the proxy plant for capacity. ELPC agrees with that a NGCT is the best measure of DTE's incremental cost avoided by entering into long-term QF contracts. Therefore, ELPC believes that Staff's capacity cost proposal is just and reasonable. Brief pp 6-7 ELPC witness Jester's testimony is consistent with Staff witness Harlow's testimony, (See 2 TR 103), that NGCTs are the resource most commonly used to provide the reserve margin a utility needs to meet MISO capacity requirements. *See* 2 TR 196. ELPC also agrees with Staff's proposed adjustment to capacity values based on the Effective Load Carrying Cost (ELCC) of the QF and the proxy plant.

ELPC agrees with Staff's proposal to use the forecasted variable costs of a NGCC plant with an adjustment for the fixed investment cost attributable to energy. ELPC believes that Staff's proposal best reflects DTE's avoided energy costs. ELPC also agrees with Staff's proposal to allow QFs three options to choose from for DTE's avoided cost of energy so long as the Commission's approved avoid cost method retains Staff's three energy option approach and Staff's recommendation to give QF's ability to select an option. Brief pp 11-13. ELPC believes that Staff's three option approach for DTE's avoided cost of energy complies with PURPA as long as the Commission retains all three alternatives with selection made by QF. *See* 18 C.F.R. § 292.304(d) (requiring rates for purchase "at the option of the qualifying facility" to be based either on avoided costs calculated at the time of delivery or avoided costs calculated at the time the obligation is incurred). In addition, ELPC argues that Staff's proposal to provide QFs with three options for avoided cost of energy complies with PURPA only if Staff's NGCC plus ICE option is retained as one of the QFs options. *Id.*

2. <u>City of Ann Arbor (CAA)</u>

a. Transfer Price Schedule

The City of Ann Arbor (CAA) argues in its brief that the Commission's Transfer Price Schedule is the only avoided cost methodology that meets PURPA's requirements that avoided costs be just and reasonable, in the public interest, and not discriminate against QFs. Brief pp 43-45. CAA argues the Transfer Price Schedule is the appropriate proxy for DTE's avoided cost for both energy and capacity because it is based on a NGCC unit and complies with PURPA. In addition CAA argues that the Transfer Price Schedule's 20 year projected cost period provides an avoided cost schedule that could be the basis of a QF multi-year, long-term power purchase agreements. *Id*

CAA argues that the passage of 2016 PA 342 reaffirmed Michigan's Renewable Portfolio Standards by continuing RPS for five years, followed by public utility renewable energy and energy waste reduction "goals". The CAA argues that PA 342 assures that the transfer price schedule will continue to be a relevant, reasonable and prudent method for calculating "the energy and capacity (nonrenewable market price component) through a new long term power purchase agreement for traditional fossil fuel electric generation," *Id.*

Sections 45 and 49 of 2008 PA 295 required the development of a Transfer Price Schedule. In Case No. U-15800, The Commission issued an order establishing the Transfer Price Schedule. The Commission's order in pertinent part provides as follows:

> In a renewable energy plan, PSCR transfer revenues are subtracted from the total cost of compliance, as determined by Section 47(2) (a). The transfer price is a primary determinant of the incremental cost of compliance. The PSCR transfer price:
>
> (a) is unique to each provider;
>
> (b) reflects the value of long-term capacity and energy;
>
> (c) is not the current MISO market price of energy, but may use historical MISO prices as a starting point for a 20-year projection of the value of renewable energy and capacity;

(d) need not be tied to the avoided price of a new conventional coal-fired facility; and

(e) other factors determined relevant by the Commission.

The transfer price may be separately calculated for differing renewable technologies to reflect availability and the value of capacity; e.g., the capacity value of a landfill gas facility may differ from the capacity value of a wind farm.

Commission's Order in. U-15800, December 4, 2008, p. 25- 26.

CAA argues that the Commission's adoption of either DTE's or Staff's avoided cost methods would discourage cogeneration and small power production and provide QFs with lower payments than DTE receives for comparable facilities. CAA believes that Staff and DTE support a Transfer Price Schedule for DTE's own facilities that would pay DTE between 26% to 34% more for its generation than is being proposed under either Staff's or DTE's methods, according to the values set forth in Exhibits A-1 (Revised) and A-3. Brief p 50

CAA argues that it would not be in the public interest to pay QFs a reduced rate in order to save DTE's consumers money. CAA believes the lowest cost option would be discriminatory toward a QF and violates the goal of PURPA, FERC's rules and regulations implementing the law. Brief p 51.

3. <u>Great Lakes Renewable Energy Association (GLREA) Comparative IRP Avoided Costs</u>

GLREA argues Commission should consider a method based on a comparative IRP analysis. Brief pp 4- 5. GLREA witness Crandall testified that the comparative IRP method compares a long-range expansion plan without SPPCFs (QFs) to a long-range expansion plan with QFs. The difference between the two long-range plans is the QF's avoided cost. GLREA believes that the IRP method, despite its complexity relative to proxy methods, yields a more detailed and comprehensive analysis which does not rely on the proxy plants or other approximations. GLREA believes the incremental effort to complete a comparative IRP analysis would be small because it uses the same long-term projections of load, fuel costs, resource expansion plans, inputs, and methods that DTE uses in its long term planning. GLREA witness Crandall recommends that the IRP analysis be completed using a block of QFs rather than individual projects because most QFs are relatively small. The costs (payments) would be made on a per unit basis for any QF projects within that block.

GLREA disagrees with DTE's conclusion that capacity and energy costs for an avoided plant must be based on the natural gas combined cycle proxy plant and that it is inappropriate to develop avoided costs that combine MISO pricing with unrelated capacity costs .Brief pp 9-10. GLREA argues that DTE's avoided cost method approach focuses on the capacity and energy costs of a proxy (NGCC) for an avoided plant and understates avoided costs. 2 TR 122. GLREA believes that the comparative IRP analyses method is a more sophisticated analyses used to calculate the production cost with and without the QF resources. Brief p 5.

E. <u>Staff's HPPM Is Reasonable and Prudent and PURPA Compliant</u>

DTE rejects Staff's and the TAC reports recommended Hybrid Proxy Plant Method (HPPM) because DTE believes the HPPM does not accurately represents DTE's avoided costs. Specifically DTE believes the HPPM:

- Arbitrarily assigns fixed cost the variable energy component which significantly over or under compensates for the total energy and capacity value; and

- Is overly complex for no identifiable value.

DTE argues that HPPM is overly complex because it requires the calculation of three components to calculate the rate – the energy, capacity, and ICE components with three energy component options. DTE witness Padgett testified that each energy option includes an ICE adder which DTE believes transfers some capacity costs to the energy rate resulting in partial QF compensation for capacity costs in the energy payment during when DTE may not need capacity. 2 TR 307-310.

DTE also rejects Staff's recommendation for a single cycle combustion turbine (CT) as the capacity proxy plant because DTE believes it has adequate peaking capacity for the foreseeable future*. Id.* DTE argues that it acquired two plants last year and is not projecting any future capacity needs. In support of DTE's capacity positions DTE provided Exhibit A-2 and A-5.

GLREA witness Crandall testified that Staff's avoid cost methods are in general the methods which have been used for decades throughout the United States to calculate avoided costs. However, GLREA believes that Staff's method does not include DTE's full avoided costs because it does not include the following:

- Avoided transmission and distribution costs;
- Quantifiable environmental costs (e.g., purchasing RECs);
- Line losses; and
- Reserve margin requirements (where the alternative resource, by reducing load supplied by the utility, reduces the utility's capacity requirement by the load plus the reserve margin).

2 TR 113

GLREA believes that Staff's options for calculating avoided capacity and energy costs within the hybrid proxy plant method are generally valid but all avoided costs must be included and properly reflected in each specific combination and purpose served by the avoided cost calculation. 2 TR 113.

CAA argues that Staff's energy components use of MISO's LMP is discriminatory and unreasonable proxy for avoided energy costs – either on a short-term basis, or using this short-term pricing over the QF's contract. 2 TR 39. CAA believes that Staff's proxy must include other energy costs avoided to prevent an undervaluation of the energy component to the QF. CAA argues that Staff's use of MISO's ZRCs to determine the amount of capacity credit produced by a QF to determine avoided cost payments is inappropriate. CAA believes that Staff's use of us the ZRC as a pricing mechanism to factor "system daily and seasonal peak period" into capacity costs results in the lowest cost option and undervalues QF capacity. CAA argues that Staff's approach does not reflect DTE's full avoided capacity costs. Brief p 38.

DTE, and the intervenors in this matter, have expressed beliefs previously provided in this decision that Staff's HPPM if adopted by the Commission would not reflect DTE's full avoided costs. Some have argued that Staff's HPPM is unreasonable, discriminatory and in violation of PURPA. I disagree. PURPA Section 210(b) requires an "electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility" at rates that are:

> "just and reasonable to the electric consumers of the electric utility and in the public interest," and does "not discriminate against qualifying cogenerators or qualifying small power producers."
>
> 16 USC § 824a-3(b).

There is no dispute among the parties that the theoretical foundation for Staff's HPPM is a reasonable FERC approved proxy unit avoided cost methodology. The evidence shows that Staff made great effort during the TAC committee meeting process to solicit and consider recommendations from DTE and from most if not all, the intervenors in this matter. Staff, ELPC, and to some extent GLREA, agree that Staff's HPPM is a reasonable and prudent avoided cost method. All parties, save DTE, have submitted extensive evidence that DTE's preferred avoided cost method is unreasonable and arguably not PURPA compliant for a variety of reasons previously outlined in this decision.

I find that Staff's HPPM for capacity and energy would result in rates to QFs that comply with PURPA because the rates derived from Staff's HPPM would be "just and reasonable to the electric consumers of the electric utility and in the public interest," and would "not discriminate against qualifying cogenerators or qualifying small power producers." See 16 USC § 824a-3(b). Therefore, I recommend that Staff's HPPM is reasonable and prudent and recommend the Commission adopt Staff's HPPM as the Commission's avoided cost methodology.

F. Biennial Reviews

Federal regulations at 18 CFR § 292.302(b), require DTE to report every 2 years DTEs avoided cost data and capacity planning information for a 10 year period. 2 TR 72. Staff's biennial review proposal includes, when necessary, Commission review of the standard offer during a contested case proceeding. Staff believes that this process would allow the Commission to update DTE's standard offer cap, depending on DTE's capacity needs. Brief p 10 2 TR 72, 74-75. Staff's proposal also includes a provision that if DTE does not project a capacity need during its 10-year planning horizon before the

Commission's biennial review, then DTE could file a request to adjust the standard offer to the PRA. 2 TR 75-76.

ELPC agrees with Staff' witness Harlow's position,(See2 TR 99), that DTE's avoided cost should be based on capacity needs over a long-term planning period to avoid discrimination against QFs and to maximize customer benefit from purchases from QFs. ELPC believes that DTE's proposal to link capacity payments to a five-year planning horizon would undervalue DTE's avoided cost of deferring capacity additions because DTE is looking beyond five years when deciding whether to build a large generation plant.

DTE uses at least a ten-year forecast in its own capacity planning and it has identified capacity shortfalls in that same ten-year forecast or shorter period to determine DTE's must purchase capacity from a QF under PURPA. In response to a discovery request, DTE provided a ten-year forecast which shows DTE has capacity shortfall of 503 megawatts in forecast year 6 and a 265 MW to 1304 MW shortfall, in years 7 through 10. See 2 TR 57.

GLREA, like ELPC, believes that DTE's proposal to utilize a 5-year planning horizon undervalues future avoided capacity costs. 2TR 113. Despite these concerns DTE believes the continued use of biennial avoided cost filings would:

- Provide a mechanism to keep DTE's avoided capacity and energy costs current;
- Identify DTE's capacity needs over a subsequent 5 year period; and
- Allow the Commission and potential QFs access to updated avoided cost information.

. 2 TR 306

DTE argues that it's biennial filing" would include DTE's projected capacity needs identified in DTE's latest PSCR plan case 5-year forecast. DTE believes that this approach would eliminate duplicative contested case proceedings and would allow for the use of one set of data. DTE does not support a 10 year planning because it believes that projecting capacity needs over a 10-year or longer period would:

- Increase uncertainty; and
- Require imprudent capital and other resources costs which would be passed on to DTE customers*.* *Id.*

Staff proposes that if DTE has any capacity need during a 10-year planning horizon then DTE must pay a QF for its capacity. Brief p 5. According to Staff's proposal existing QFs will be treated differently from new QFs. When an existing QF renews its QF contract, the contract will include a capacity payment at the full standard rate capacity. The capacity payment will be included regardless of DTE's capacity need during the PURPA 10-year planning horizon. 2 TR 99.

Staff also proposes that for new QFs, not part of DTE's portfolio, if DTE's capacity need over the 10-year planning period is fully met QFs would be compensated at the cost of MISO's Planning Resource Auction (PRA) 2 TR 99 . If there is a capacity need during the 10- year planning period then avoided costs would be based on Staff's NGCT proxy plant.

I agree with Staff, GLREA and ELPC that a short-term capacity-planning horizon would "unfairly discriminate against qualifying facilities by using time horizons and valuations that the utility does not assign to its self-build options." (See 2 TR 154) and undervalue future avoided capacity costs. Staff's biennial review proposal is reasonable and prudent and I recommend the Commission adopt Staff's biennial review proposal and require DTE to report every 2 years DTE's avoided cost data and capacity planning information for a 10 year period. Staff's planning period capacity proposal is also reasonable and prudent and I also recommend the Commission adopt Staff's QF capacity payment proposal.

G. Standard Offer Tariff

DTE supports the current design capacity of 100kW or less standard offer tariff limit. DTE believes that its current standard offer tariff's 100kw cap:

- Complies with PURPA;
- Has not posed any known problems with existing QF s, and
- There are no compelling reasons to create additional regulatory burdens on DTE in the current regulatory environment.

2 T RR 308, 313

DTE's proposed standard offer tariff may be found in Exhibit A-6 (see Exhibit A-6 Proposed Tariff Sheet – Standard Contract Rider No. 5). DTE witness Bloch testified regarding the necessary changes and updates to the existing DTE Riders. See 2 TR 356-357.

DTE witness Bloch testified that DTE's proposed tariff is consistent with the following policy considerations as discussed by DTE witness Padgett:

1) Passage of the Energy Policy Act of 2005 and subsequent FERC approval of DTE's application for a waiver mandatory purchase obligation for QF's with net capacity greater than 20 MW. A 20 MW size limit was added to the availability section of the tariff.
2) Capacity and energy purchase agreements under the standard offer tariff is limited to when DTE needs capacity.
3) Tariff availability has also been changed to indicate the tariff is only available to DTE full service customers. Id.

Staff proposed several revisions to DTE's standard offer tariff. These revisions are provided in Exhibit S-1. Staff's standard offer tariff recommendations are as follows:

- a methodology based on the utility's capacity needs to determine the standard offer tariff QF design capacity size cap;
- standard offer contract length of 5, 10 or 15 years;
- credit for line loss savings according to the location of the QF on DTE's distribution system;
- three available options to the QF for energy payments;
- capacity payment based on Staff's avoided capacity cost calculation;
- transfer of Renewable Energy Credits (RECs) to DTE as part of the standard offer;
- Commission review of the standard offer tariff every two years as part of the avoided cost biennial review process;
- Commission review and consideration of standard offer contracts for approval on an ex parte basis.

1. Standard Tariff Cap

Staff proposes the following standard offer tariff cap. If DTE has capacity need during it PURPA 10-year capacity planning horizon, then Staff recommends:

- 1 MW Standard Offer size cap when the utility needs 0 – 100 MW during the succeeding two years;
- 2 MW cap when up to 200 MW is needed;
- 3 MW cap when up to 300 MW is needed;
- 4 MW cap when up to 400 MW is needed; and
- 5 MW cap when more than 400 MW is needed.

Brief p 8, 2 TR 75

The standard offer tariff filed by DTE limits the tariff' to QFs that have a capacity of 100 kW and less. PURPA requires the standard offer be made available to QFs with a design capacity of 100 kW and less. See, 18 CFR § 292.304(c) (1). PURPA provides that the standard offer may be made available for purchases from QFs greater than 100 kW. 18 CFR § 292.304(c) (2).

Staff proposes a standard offer tariff cap of 1 MW .See Exhibit S-1. Staff agrees with CAA that DTE's proposed 100 KW standard offer cap complies with PURPA but is very low. 2 TR 283-284. Staff's tariff limit proposal would encourage development of QF projects and allow the Commission to achieve PURPA's goals by increasing the standard tariff limit as DTE's capacity needs change. I recommend that Staff's tariff proposal is reasonable and prudent and should be adopted by the Commission.

2. <u>Contract Length</u>

DTE believes that the length of QF contracts should be left to negotiation process. Mr. Padgett testified:

> "…DTE Electric believes that arbitrarily setting a contract length as part of this methodology review is not in the interest of either party and should be left to the negotiation process. For expiring contracts, the contract life should again be left to the negotiation process so the financial status and needs of the project can be reviewed and compared against the applicable market conditions. Other considerations such as the utilities [sic "utility's"] relevant avoided cost at the time of contract renewal and ongoing need for the project will likely be more significant factors than contract life when considering renewal."
>
> 2 TR 312

Staff recommends QF standard offer tariff contract term options of 5, 10 or 15 years. Staff witness Baldwin testified that existing PURPA contracts and recent Act 295 contracts are typically 5 years or longer. 2 TR 76-77. Staff does not agree with DTE's recommendation that does not include any contract term length or any ability to forecast costs. Brief p 9. Staff believes that PURPA allows a QF to obtain a contract with a forecasted rate over an appropriate contract term. See 18 CFR § 292.304(d) (2).

Staff argues that the short QF contract term proposed by DTE would not be consistent with FERC rules. Section 210 of PURPA, 16 USC § 824a-3, and FERC's regulations require the Commission, to encourage cogeneration, small power production, and small geothermal production for wholesale power supply. Staff argues that the Commission has the authority to determine appropriate specific terms of the must purchase obligation. "[A] state may take action under PURPA only to the extent that that action is in accordance with the Commission's rules."*Allco Renewable Energy Ltd*., 146 FERC ¶ 61107 (Feb. 20, 2014); See also *FERC v Mississippi*, 456 US 742, 751 (1982); 16 USC § 824a-3(f).

FERC's rules at 18 CFR 292.304(e) (iii) provide that the Commission should consider "the terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance." FERC also discussed the long-term length of contracts in its comments on PURPA in Order 69. See Order 69, 45 Fed Reg at 12,226.

ELPC rejects DTE's position that all QF contract terms be negotiated with DTE. ELPC believes that DTE's position would:

- Increase transaction costs;
- Be unnecessary and hinder QF development;
- Prejudice QFs through inadequate contract terms.

Brief p. 23

ELPC also believes the Commission should set contract terms of no less than 15 years to prevent discrimination against QFs. ELPC argues that an adequate contract term length:

- Prevents discrimination against QFs;

- Furthers PURPA's goals;
- Allows QFs to recover costs;
- increases the utilization of cogeneration and small power production facilities; and
- Reduces reliance on fossil fuels.

Brief p 22

ELPC witness Schumaker testified that:

- 15 years is the shortest "term required to make a solar project financeable." 2 TR 23;
- Debt providers finance QF projects for the length of a Power Purchase Agreement (PPA) or less;
- More debt can be secured by a contract with a longer the standard offer term. 2 TR 239;
- With more debt secured, the ability to finance the QF project is not hindered. 2 TR 241.

CAA argues that its QFs need 20-year or longer contract terms in order to ensure recovery of the capital expenditures." See 2 TR 262.

GLREA's witness Crandall recommends a QF contract length of a minimum of 17.5 years (at the discretion of the QF). Mr. Crandall testified that GLREA's recommendation is consistent with Section 6j (13) (b) of Act 304, which provides in pertinent part:

> The financing period for a qualifying facility during which previously approved capacity charges shall not be subject to commission reconsideration shall be 17.5 years, beginning with the date of commercial operation, for all qualifying facilities, except that the minimum financing period before reconsideration of the previously approved capacity charges shall be for the duration of the financing for a qualifying facility which produces electric energy by the use of biomass, waste, wood, hydroelectric,

> wind, and other renewable resources, or any combination of renewable resources, as the primary energy source.
>
> MCL 460.6j (13) (b)

Mr. Crandall testified that avoided costs should be set at a level that is:

- Just and reasonable;
- Fair and nondiscriminatory;
- At a level which promotes the development of QFs; and
- Consistent with PURPA and FERC regulations and interpretations.

2 TR 128-129

Mr. Crandall also testified that a longer contract term such as a minimum of 17.5 years (at the discretion of QF) would be reasonable and in the public interest. A longer contract term would:

- Enable an accurate comparison between QF projects and DTE's building or purchasing a new power plant or purchasing power;
- Facilitate the securing of financing of new or existing QFs; and
- Ensure viability through government approval.

Id.

I agree with Staff, CAA, ELPC and GLREA that DTE's contract length proposal is unreasonable. I also agree with CAA, ELPC, and GLREA that Staff's proposed 5, 10, or 15-year contract periods are too short and would not provide sufficient duration to obtain a return on capital investments. I find a contract term up to 20 years would be reasonable and prudent and comply with PURPA. I recommend the Commission allow a QF to select a contract term up to 20 years.

3. Line Loss and 18 CFR 292.304 Factors

DTE indicated that it will consider the principles and factors discussed in 18 CFR 292.304 when determining applicable QF capacity and energy rates for QF purchases. DTE believes that, due to variability in project circumstances and capabilities, the application of the factors should be negotiated during the contract negotiation process. 2 TR 308, Brief p 18.

ELPC argues the Commission should establish a process to quantify technology-specific avoided cost factors such as transportation, distribution, delivery, and system costs. ELPC believes that these are the real distributed generation costs that are or can be avoided. *See* 2 TR 155. ELPC argues that FERC regulations provide an avoided cost method, to the extent practicable, must take into account these factors when determining the full and fair QF avoided costs.

FERC regulations outline "factors affecting rates for purchase" that should be considered in combination with energy and capacity considerations, when determining a utility's avoided cost. FERC regulations provide that the following factors "shall, to the extent practicable, be taken into account." 18 CFR § 292.304(e).

(1) Data regarding the utility's cost structure and plans to add capacity;

(2) The availability of capacity or energy from a qualifying facility during daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;
(ii) The reliability of the QF;
(iii) Contract terms;
(iv) The extent to which scheduled outages of the qualifying facility can be coordinated with scheduled outages of the utility's facilities;
(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies;
(vi) The individual and aggregate value of energy and capacity from QFs on the electric utility's system;

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from QFs.

(3) The relationship of the availability of energy or capacity from the QF to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use.

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

18 CFR 292.304(e)

CAA argues that Staff's proposed standard offer fails to meet PURPA's and FERC rules requirements because it fails to consider a number of factors. See Brief pp 40-41.

Pursuant to Section 292.304(c) (3) (I), standard offer rates for purchases are required to be consistent with both the standards for avoided costs (rates for purchase, Section 292.304(a)), and the "factors affecting rates for purchases" in Section 292.304(e). The factors listed in Section 292.304(e) must be considered by the Commission "to the extent practicable." CAA argues that because neither Staff nor DTE considered the required factors the standard offer tariff does not reflect DTE full avoided costs and therefore is set discriminatorily low. Brief p 41.

Staff proposes that the standard offer tariff include a sentence recommending that line losses be evaluated on a case-by-case basis. 2 TR 78. Staff disagrees with DTE's statement that line loss cannot be quantified and should not be included with respect to a standard offer tariff. 2 TR 52, 59-61.

I agree with Staff's proposal to include a sentence in the tariff recommending that line loses be evaluated on a case by case basis. Other principles and factors discussed in 18 CFR 292.304, due to variability in project circumstances and capabilities, should be negotiated during the contract negotiation process. I recommend the Commission include language in the tariff which requires a case by case evaluation of line loss and directs that other factors be subject to negotiation.

4. Forecasted Costs

Staff argues that DTE's proposal for standard contracts, without the option of long-term forecasted costs, is not reasonable, because the proposal fails to balance the QF's and DTE's rights. There is a dispute whether avoided costs can be forecasted as well as the period or term upon which forecasted avoided costs should be based for the standard offer. Staff argues that DTE's proposed standard QF contract terms without the option of any guaranteed contract length would not:

- Compensate QFs for their capacity contributions to DTE's system, and
- Violate FERC regulations standard contract provisions.

Brief p 11

FERC's must purchase obligation regulations at 18 CFR § 292.304(d) provide that each qualifying facility shall have the option either:

> (1)To provide energy as the qualifying facility determines such energy to be available for such purchase, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or
>
> (2)To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (I) The avoided costs calculated at the time of delivery; or
> (ii) The avoided costs calculated at the time the obligation is incurred.

Brief p 12

Staff argues that if a QF contractually agrees to make capacity available when DTE would otherwise construct a new generation facility then the QF is entitled to avoided costs based on the construction costs of a new facility. Staff relies upon FERC Order 69 which provides in pertinent part:

> "If a qualifying facility provides [contractual or other legally enforceable assurances that capacity will be available to displace future new capacity], it is entitled to receive rates based on the capacity costs that the utility can avoid as a result of its obtaining capacity from the qualifying facility."
> *See, Regulations Implementing Section 210 of the Public Utility Regulatory Policy Act of 1978,* Order No. 69, 45 Fed. Reg. 12,214, 12,225 (Feb. 25, 2980).

Staff further argues that DTE's proposed QF contract term would be discriminatory towards QFs and would not provide QF compensation for capacity consistent with FERC order 69. FERC order 69 provides in pertinent part:

> "[If a QF] offers energy or sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, the rate for such a purchase will be based on the avoided capacity and energy costs."
>
> Order 69, 45 Fed. Reg. at 12,226; See 2 TR 70.

Staff argues that because QFs have the long-term ability to defer DTE's construction of new generating units. QF contract terms contract terms should allow QFs to be compensated for their ability to meet DTE's capacity needs. 2 TR 144, 2 TR 102.

Staff rejects DTE's argument that a QF contract based on forecasted costs does not provide a fixed term during which power would be available. Without a firm commitment DTE believes that it could not cancel planned generation. Staff argues that DTE's proposal would be contrary to PRUPA and FERC rules. Staff relies on PURPA, section 210, 16 USC § 824a-3, which allows a QF to choose forecasted costs, e.g. costs calculated at the time the “obligation is incurred.” FERC rule 18 CFR § 292.304(d) (2) (ii) provides a QF shall have the option to enter into a contract or other obligation to sell both energy and capacity based upon the avoided costs calculated at the time the obligation is incurred. Rule section 292.304(d) provides a QF also has the unconditional right to choose whether to sell its power ‘as available’ or at a forecasted avoided cost rate pursuant to a legally enforceable obligation.” *Hydrodynamics Inc. et al,* 146 FERC ¶ 61,193, p 31. The cost at the time the obligation is incurred has been interpreted to mean forecasted costs.

Staff rejects DTE’s belief that DTE’s proposal is in the best interest of ratepayers because forecasted costs over a period of time could benefit ratepayers or the QF, depending on whether the forecasted costs favor the QF or the ratepayer versus actual costs over time. 2 TR 310-311.

Staff rejects DTE witness Padgett‘s belief that costs should not be based on a snapshot in time. 2 TR 310-311. Staff argues that FERC has indicated that forecasted costs are a fair option under PURPA. *Hydrodynamics Inc. et al,* 146 FERC ¶ 61,193, p 31. Staff rejects DTE’s proposal because it would eliminate a QF’s right to obtain pricing based on the avoided costs calculated at the time the obligation is incurred or based forecasted costs at the option of the QF.

I agree with Staff that QF contracts that use forecasted costs area reasonable and prudent. I recommend the Commission adopt this finding.

5. <u>QF Energy Payment Options</u>

Staff proposes the same three standard tariff energy rate options as it proposed for nonstandard tariff QF purchases. These options are:

- The LMP at the time of delivery,
- LMP Energy Rate Forecast and
- Proxy Plant Variable Rate Forecast.

Staff witness Harlow provided the LMP Energy Rate Forecast in Exhibit S-6 and the Proxy Plant Variable Rate Forecast is provided in Exhibit S-5. 2 TR 87, 2 TR 104-105.

DTE proposes the same standard tariff energy method proposed for non-standard tariff purchases. DTE's avoided capacity cost method is based on a Natural Gas Combined Cycle (NGCC) power plant which includes its capacity, O&M and energy costs. DTE argues that when DTE does not need capacity, its avoided energy cost would be the MISO locational marginal price (LMP). DTE believes that if it does not need capacity to serve its full service retail customers then DTE should only be required to purchase energy from a QF at DTE's incremental cost of energy. DTE witness Padgett testified that DTE's avoided energy cost during periods when capacity is not needed is the wholesale electric market spot price for energy or LMP in the MISO wholesale energy market. 2TR 312.

I find that Staff energy options are reasonable and prudent and recommend the Commission adopt Staff's energy three option proposal.

6. <u>QF Capacity Payments</u>

Staff's proposed standard tariff capacity rate is the same as the non-standard tariff rate. Staff's proposed standard tariff capacity rate is equal to the capacity costs of a Natural Gas Combustion Turbine (NGCT). 2 TR 78, See Exhibit S-4 .DTE's proposed standard tariff is provided in Exhibit A-6. The tariff provides that DTE will only make a standard tariff capacity payment to a QF if DTE has a capacity need.

DTE argues that it should only be required to pay for QF capacity when it projects a capacity need in the next 5 years. DTE believes that PURPA does not require DTE to prospectively pay for new QF capacity when DTE does not need capacity to serve its full service retail customers. DTE further argues that if DTE has or is projecting that it has adequate capacity to serve its retail customers, then DTE's obligation to purchase from a QF is limited to DTE's avoided energy cost. 2 TR 307 Brief p. 17. In support of this position DTE witness Padgett testified:

> "PURPA defines avoided cost as:
>
> The **incremental** costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility **would** generate itself or purchase from another source." 18 CFR 292.101(b) (6) (emphasis added)"
>
> 2 TR 307

DTE argues that a cost is not "avoided" and is neither "incremental" nor "would" be generated if it is the result of a subsidy, theory, policy or speculation about projected future needs. DTE argues that its current Commission approved avoided cost is based on actual avoided cost methodology using the DTE Belle River generation unit. DTE witness Padgett also testified that when DTE does not need QF capacity DTE's avoided energy cost is the wholesale electric market spot price for energy or LMP in the MISO wholesale energy market. 2 TR 312 Brief p 18.

In its Reply brief DTE argues that its position regarding QF capacity payments is consistent with the following PURPA provisions:

- "Rates for purchases shall be just and reasonable to the electric consumer of the electric utility and in the public interest";
- "Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases", and

- "Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

See 18 CFR 101(b) (6) and 292.304)

DTE argues that *Am. Paper Inst. V. Am. Elec. Power Serv. Corp.,* supports DTE's position that FERC's PURPA rules make it clear that DTE's consumer interests are paramount:

> "We interpret the 'just and reasonable' language of Sec. 210(b) to require consideration of potential rate savings for electric utility consumers. Of course, even when utilities purchase electric energy from qualifying facilities at full avoided cost rather than at some lower rate, the rates the utilities charge their customers will not be increased, for by hypothesis the utilities would have incurred the same costs had they generated the energy themselves or purchased it from other sources… Unless the 'just and reasonable' language is to be regarded as mere surplusage, it must be interpreted to mandate consideration of rate savings for consumers that could be produced by setting the rate at a level lower than the statutory ceiling….It bears emphasizing that the full avoided cost rule is not as inflexible as might appear at first glance…a qualifying facility and a utility may negotiate a contract setting a price that is lower than a full avoided cost rate. Sec. 292.301(b)(1). Because the full avoided cost rule is subject to revision by the Commission as it obtains experience with the effects of the rule, it may often be in the interest of a qualifying facility to negotiate a long-term contract at a lower rate. The Commission's rule simply establishes the rate that applies in the absence of a waiver or a specific contractual agreement.
>
> *Am. Paper Inst. V. Am. Elec. Power Serv. Corp.,* 461 U.S. 402, 415-416 *fn* 9; 103 S. Ct. 1921; 76 L.Ed.2d 22 (1983)

DTE argues in its Reply Brief that the Supreme Court, Congress and FERC have indicated:

- Retail electric utility consumers rates must be considered when determining avoided costs;
- PURPA was not intended to merely subsidize QF projects;
- An "avoided cost" cap on payments to QFs was not intended to be a required utility payment to QFs;

- Utility payments to QFs are intended to, at worst, leave electric utilities indifferent to that utility's next increment of generation or next purchase;

- Utilities and QFs can and should negotiate contracts because that just might be in everyone's best interest.

Reply Brief p. 5

GLREA rejects DTE's proposal not to make capacity payments to QF when DTE has no capacity need. GLREA's witness Crandall testified that DTE's tariff terms are unreasonable, logically inconsistent, flawed and incorrectly assume that when capacity is needed, the QF is more valuable than when capacity is not needed. 2 TR 118-119. Mr. Crandall testified that DTE's proposal illustrates how DTE's proposed avoided energy costs methods and calculations understate the true value of QF capacity and energy. He provided two examples:

- Avoided capacity value is zero when DTE does not need capacity;
- Pay avoided energy at the incremental production cost of the avoided generating plant rather than the actual LMP.

Id.

GLREA believes that QF capacity has value even when DTE has no need for new capacity for the following reasons.

- a QF with a long life would have value because it would provide capacity beyond the contract period;
- DTE's proposal to not pay for capacity when DTE has sufficient capacity deprives MISO of the QF capacity and the QF of revenues.

GLREA argues that if DTE is allowed to avoid making capacity payments to the QF then those actions would:

- Reduce QF revenue;
- Make it more difficult for the QF to obtain financing;

- Create barriers to the QF project construction;
- Be inconsistent with PURPA's intent to levelized payments, stabilize and advance revenue, and increase project financially viability.

Brief pp 9-10

CAA argues that DTE's PURPA QF purchase obligation arises when a QF offers capacity with firm contractual requirements. See Order 69, 45 Fed Reg at 12,216. PURPA was enacted "to encourage cogeneration and small power production." Order 69, 45 Fed Reg at 12,215. CAA argues that once a QF can provide "sufficient legally enforceable guarantees of deliverability," then DTE must purchase both the QF's capacity and energy. Order 69, 45 Fed Reg at 12,216. See Brief p 25.

CAA argues in it Reply Brief that DTE has provided no legal authority which shows that DTE is exempt from its federal must purchase obligation under 18 CFR § 191.303(a) when DTE does not project a need for capacity. Reply Brief p 9 .CAA argues that if DTE could relieve itself of PURPA obligations based of its own capacity projections then it would undo PURPA's intent to prevent utilities from refusing to buy from QFs or to fairly compensate QFs for power. Id.

I agree with CAA and GLREA that If DTE is allowed to avoid making capacity payments to the QF when DTE projects no capacity need then DTE action would result in the following:

- Reduced QF revenue;
- Increase the difficulty for QFs to obtain financing;
- Create barriers to the QF project construction.

In addition the non -payment of capacity payments would be inconsistent with PURPA's goals "to encourage cogeneration and small power production." When a QF offers DTE capacity with firm contractual requirements DTE's PURPA QF purchase obligation arises. See Order 69, 45 Fed Reg at 12,216.

DTE's proposal is not reasonable and prudent and I recommend the Commission require DTE to make capacity payments to QF consistent with Staff's capacity avoided costs proposal and consistent with Staff's biennial and 10 year planning forecast proposal. Staff's proposal properly balances QF and DTE's retail rate payer interests and in doing so complies with PURPA section 210(b).

7. Transfer of Renewable Energy Credits (RECs)

Staff also recommends DTE receive the Renewable Energy Credits (RECs) when a QF and DTE enter into a standard offer contract. Staff argues that this approach balances the interests of QFs and DTE 2 TR 78. According to Staff's proposal REC ownership would be negotiated for QFs that choose to negotiate a contract rather than to accept a standard offer contract. Brief p 10.

DTE argues that it should receive the value of RECs and that the Commission should not leave the disposition of RECs to future negotiations. DTE believes that if a QF generates RECs, then the RECs are part of the total QF product value that DTE is required to purchase. Because PURPA requires DTE to purchase generally renewable QF energy and capacity DTE believes that it should receive any RECs. DTE believes that if it does not receive the REC's with a QF purchase then its full service customers would have to pay extra for RECs. 2 TR 313-314. Brief p 19.

CAA rejects DTE's proposal to retain the RECs produced by the QF without compensation. Brief pp 31-35. CAA argues that the QF's RECs have a value therefore a QF should be compensated for that value. DTE uses QF RECs to meet its State renewable portfolio requirements. DTE witness Padgett testified: "DTE's planning includes receiving 80% of RECs from PURPA facilities in order to achieve compliance with PA295 through 2029." 2 TR 313.

DTE witness Padgett further testified:

> PURPA requires the Company to purchase energy and capacity, if needed, from QFs in part because the energy being produced is either renewable or has environmental benefits. Full service customer should realize those benefits as part of the purchase obligation going forward and should not have to pay extra for those benefits separable from the energy and capacity being purchased.
>
> 2 TR 314

CAA argues that if the QF produces energy from a renewable source then the QF should be compensated for any REC value. Brief p 32. CAA rejects DTE's argument that DTE's customers should not be required to pay for RECs. CAA argues that DTE's avoided cost calculations are not based on costs of a renewable resource, but on a fossil fuel proxy or on market costs. Id.

CAA's witness Steglitz testified:

> "Staff's proposal effectively gives away public property – that is, renewable energy credits that belong to the City, for no additional benefit. If RECs are going to go to the utility under the standard offer, then there should be a real exchange of value for them and the City should see an increased avoided cost rate, an increased contract term, or some other tangible benefit to justify the loss to the City of the environmental benefit."
>
> 2 TR 263.

CAA argues that the renewable energy requirements of 2008 P.A. 295, §§ 27 and 29 should be reflected in the avoided costs set for CAA's QFs. CAA believes that DTE's position that RECs generated by QFs should be assigned to the utility upon payment of avoided costs is a violation of FERC's requirements Brief p 33.

CAA argues that the following Michigan statues require:

- Utilities to generate or purchase 10% of their supply from renewables currently. MCL 460.1027(3) (b).

- Renewables must be located in Michigan;

- A utility may not purchase less expensive out-of-state renewable energy. MCL 460.1029(1); and

- Utilities must meet a renewable standard of 12.5% by 2019 and 15% by 2021. PA 342, § 28.

Brief p 34

CAA believes that if the Commission decides RECs should be transferred to DTE upon payment of avoided costs, then under FERC's precedent, the avoided cost calculation should include the costs of other sources that will meet the REC requirements plus the cost of the fossil-fuel proxy. See, *California PUC*, 61267 Brief p 34. CAA argues that the additional costs should be based upon what DTE is paid for its own renewable generation. FERC has noted "A state may separately provide additional compensation for environmental externalities, outside the confines of, and, in addition to the PURPA avoided cost rate, through the creation of renewable energy credits (RECs)." *California PUC*, 61,268.

CAA recommends the Commission do the following:

- Allow QFs to retain REC's;

- If DTE wants a QF's RECs to meet DTE's renewable energy requirements, then DTE and the QF should negotiate a QF contract and set a REC value that is not included in the avoided cost rate.

Brief p 35

ELPC in its Reply Brief rejects DTE's argument that RECs should be separated from energy and capacity. See DTE Initial Brief at 19. ELPC argues that DTE's proposed separation violates PURPA because the renewable compliance avoided costs that DTE would receive through RECs are incremental and are not the same as those in Staff's proposed avoided energy and capacity costs methodology. ELPC Reply Brief p 9. ELPC relies upon a FERC decision in *Windham Solar LLC and Allco Finance Ltd*, 156 F.E.R.C. P61,042, ¶ 4 (2016) in which FERC wrote:

> … "a state regulatory authority may not assign ownership of RECs to utilities based on a logic that the avoided cost rates in PURPA contracts already compensate QFs for RECs in addition to compensating QFs for energy and capacity, because the avoided cost rates are, in fact, compensation just for energy and capacity."

ELPC argues that DTE incorrectly believes that RECs are "part of the total product value that the Company is being required to purchase from a QF." Therefore, ELPC believes that DTE's proposal conflicts FER*C's Windham's* PURPA interpretation. ELPC Reply Brief p 10.

ELPC also argues that DTE's contention that RECs are "part of the total product value that the Company is being required to purchase from a QF" is not supported by Michigan law. DTE Initial Brief at 19. ELPC argues that Michigan law allows DTE to purchase or otherwise acquire RECs "with or without the associated renewable energy" in order to comply with the RPS. MICH. COMP. LAWS §§ 460.1037, 460.1028(3) (effective April 20, 2017).). RECs are issued, tracked, and traded on the Michigan Renewable Energy Certification System (MIRECS). RECs have a value separate from the MW/h of energy that was expended to create the REC. ELPC Reply Brief p 10.

ELPC' witness Rábago testified that RECs associated with renewable energy generation are the property of the generator until title is voluntarily transferred by contract. 2 TR 172. CAA's witness Steglitz testified that "If RECs are going to go to the utility under the standard offer, then there should be a real exchange of value for them and the City should see an increased avoided cost rate." 2 TR 263. ELPC witness Jester testified that the Commission "use the cost of purchased renewable energy credits established in the utility's most recent renewable energy plan" when determining how to value these costs and including them in the overall full avoided cost methodology. 2 TR 217. ELPC argues that the Commission should reject DTE's RECs proposal or approve an avoided cost methodology that includes the value of a QFs RECs.

GLREA does not believe that DTE should receive the value of RECs simply because DTE and its customers are receiving QF generated power. Brief p 14. GLREA witness Crandall testified that RECs were neither contemplated nor existed when PURPA was enacted in1978. Witness Crandall testified that RECs create a new value stream that is separate and distinct from avoided energy and capacity. GLREA does not agree that QF RECs are an integral part of energy and capacity resources acquired by DTE. 2 TR 129.

I find that Staff's REC proposal is reasonable and prudent because it provides a balance between QFs and DTE's interests. Therefore, I recommend Commission allow DTE to receive the renewable energy credits (RECs) when a QF and DTE enter into a standard offer contract, but if a QF elects to negotiate a non-standard offer contract then REC ownership would be negotiated between DTE and the QF.

8. <u>Other Standard Offer Tariff Issues</u>

DTE's proposed standard offer tariff Exhibit A-6 provides in pertinent part:

> **1. Availability:**
> Full service customers with on-site small power production or cogeneration facilities 20MW and smaller that seek to sell electric output from their facility to the Company may receive service under this tariff. This rate is available

> only to customers who obtain qualifying status from the Federal Energy Regulatory Commission.
>
> Exhibit A-6 p 1

> **2. Existing Facilities:**
> b. Capacity and Energy Sales: No recognition will be made for capacity unless substantial proof is shown that the generator and protective equipment is new or equivalent to new. Refurnishing old equipment will not qualify the facility as new capacity.
>
> Exhibit A-6 p.2

CAA rejects DTE proposal to cease paying for capacity from existing QFs unless those facilities demonstrate to DTE's satisfaction, at a level of "substantial proof," that it's generating and protective equipment is "new or equivalent to new." 2 TR 360. CAA argues that DTE's current tariff, Standard Contract Rider No. 5, is available only to "Customers who employ cogeneration technology as an energy source and sell electric output of their cogeneration facility to the Company." Brief p 26. CAA points out that CAA's Barton and Superior Dams are hydro power facilities and not cogeneration facilities. CAA argues that neither DTE's current provisions of this Rider, nor, those in effect when those contracts were last negotiated, apply to CAA's hydro QFs.

CAA also rejects DTE's proposal to expand its current Rider to cover cogeneration facilities, and "[f]ull service customers with on-site small power production or cogeneration facilities 20MW an smaller that seek to sell electric output from their facility to the Company." Id.

CAA argues that DTE's proposed tariff language (which restricts QF purchases to only DTE full service customers) is discriminatory and in violation of PURPA because it:

- Violates the PURPA QF must purchase obligation, and
- Creates additional burdens and hurdles for existing QFs seeking to sell their power.

Brief p 27

ELPC argues that DTE's standard offer should be available to all QFs, not just DTE's full-service customers. ELPC argues that DTE's position conflicts with PURPA and should be rejected. PURPA regulations require DTE to purchase energy and capacity made available from QFs, *See* 18 CFR § 292.303(a). ELPC also argues there are no FERC's regulations or orders which limit DTE's must purchase obligation to full-service customers. Exemptions are found at 18 CFR § 292.309 but that regulation does include a requirement that a QF be a full-service customer. Brief p 23-24.

Staff did not provide any testimony or argument regarding either of the above standard offer tariff issues identified by CAA and ELPC. DTE has provided no legal basis or rationale for restricting its proposed standard offer tariff to QFs that are DTE full services customers. Therefore, I recommend the Commission remove the restriction from DTE's proposed tariff.

9. <u>Commission Review of the Standard Offer Tariff</u>

Staff recommends the review of the standard offer tariff every two years as part of the avoided cost biennial review process. Brief p 9. ELPC witness Rabago supports Staff's proposal for biennial review. 2 TR 166. 18 CFR § 292.302(b) requires DTE to report its avoided cost data every 2 years and DTE's capacity planning information for a 10 year period. DTE generally agrees with Staff's proposal but believes that a full contested case avoided cost proceeding would be an unnecessary burden. DTE recommends that the Commission continue with the biennial process but if new issues arise which need to be formally resolved by the Commission, then DTE would file an application with the Commission with DTE's biennial review. Staff or QFs would have the option of doing so subsequent to DTE's filing. 2 TR 319-320.

Staff recommends the Commission, during its biennial review, update the standard offer when necessary through a contested case proceeding. The contested case proceeding would allow the Commission to review DTE's capacity needs, and if necessary, update standard offer cap. 2 TR 72, 74-75. Staff recommends that if DTE's 10-year planning horizon shows DTE has no capacity needs before the time for the Commission's biennial review, DTE could file a case with the Commission to adjust the standard offer to the PRA. 2 TR 75-76.

I find that Staff's tariff review proposal is reasonable and prudent. I recommend the Commission adopt Staff's proposal.

10. Commission Review and Approval of Standard Offer Contracts

Staff supports DTE's proposal to file standard offer contracts for exparte review by the Commission. Staff witness Baldwin testified that Staff recommends DTE request exparte processing of standard officer contract processing by the Commission 2 TR 78-79. Witness Baldwin further testified that exparte processing is appropriate because standard offer contracts will include pricing already approved by the Commission. Id. DTE witness Padgett testified that DTE supports Staff's recommendation. 2 TR 321.

Staff's recommendation is reasonable and prudent and I recommend the Commission adopt Staff's recommendation.

V.

CONCLUSION

I recommend the Commission adopt the following findings and recommendations contained in this PFD at:

- Section IV E: Staff's HPPM as the Commission's avoided cost method;
- Section IV F: Staff's Avoided Cost Biennial Review and 10 year Planning Horizon;
- Section IV G1: Staff's Standard Tariff Cap;
- Section IV G 2: Contract Length;
- Section IV G 3: Line Loss and Other Factors;
- Section IV G 4: Forecasted Costs;
- Section IV G 5: QF Energy Payment Options;
- Section IV G 6: QF Capacity Payments;
- Section IV G 7: Transfer of Renewable Energy Credits;
- Section IV G 8: Other Standard Tariff Issues;
- Section IV G 9: Commission Review of Standard Offer Tariff; and
- Section IV G 10: Commission Review and Approval of Standard Offer Tariff Contracts.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Martin D. Snider

Martin D. Snider
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Martin D. Snider
Administrative Law Judge

March 31, 2017
Lansing, Michigan

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

STATE OF MICHIGAN	)	
	) SS.	Case No. U-18091
County of Ingham	)	
	)	

P R O O F O F S E R V I C E

Carol M. Casale being duly sworn, deposes and says that on March 31, 2017, she served a copy of the attached Proposal for Decision via E-Mail to the persons as shown on the attached service list.

Carol M. Casale

Carol M. Casale

Subscribed and sworn to before me
This 31st day of March, 2017.

Corinna C. Swafford

Corinna C. Swafford
Notary Public, Ionia County, Michigan
Acting in Eaton County
My Commission Expires: December 13, 2019

ATTACHMENT A
U-18091

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